Norwegian Petroleum Directorate

Offshore Norway 1999

The Norwegian Petroleum Directorate shall contribute to creating the highest possible values for society from oil and gas activities, founded on a sound management of resources, safety and the environment.

The Norwegian Petroleum Directorate was established in 1972 and performed about 360 man-years of work in 1999. The Norwegian Petroleum Directorate reports to the Ministry of Petroleum and Energy with regard to resource management and administrative matters, and to the Ministry of Local Government and Regional Development for matters relating to safety and working environment. Within the area of CO_2 tax, the Directorate exercises authority on behalf of the Ministry of Finance.

The most important tasks of the Norwegian Petroleum Directorate are to have the best possible knowledge concerning discovered and undiscovered petroleum resources on the Norwegian continental shelf, to carry out supervision to ensure that the licensees manage the resources in an efficient and prudent manner and to supervise regulatory compliance so that a responsible safety level and working environment are established, maintained and further developed. The Norwegian Petroleum Directorate also has an important role with regard to influencing the industry to develop solutions which serve the best interests of society as a whole.

The Norwegian Petroleum Directorate provides advice to supervising ministries and has been delegated the authority to stipulate regulations and make decisions regarding consents, orders, deviations and approvals pursuant to the regulations.

Through its activities, the Norwegian Petroleum Directorate shall contribute towards making Norway a leader in environmental issues.

The Norwegian Petroleum Directorate shall also provide neutral information concerning the petroleum activities to the industry, the media and to society at large.

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The Norwegian Petroleum Directorate shall contribute to ensuring that the resources on the Norwegian shelf create the greatest possible value for society. Our efforts are based on a broad interpretation of the concept of value. In addition to revenues for the State, the concept also encompasses the general welfare, a good, sustainable environment and the premise that the activities are conducted in accordance with a framework of social ethics. Financial aspects are extremely important if we are to reach society's goals, but health, safety and the environment are also important factors to this end. Therefore, the Norwegian Petroleum Directorate is concerned with ensuring that its efforts in the areas of resource management and health, safety and the environment will constitute a comprehensive contribution towards creating these values for society as a whole.

Resource growth and production

Resource growth in 1999 was lower than the net production. It is estimated that the growth as a consequence of new discoveries on the Norwegian shelf is approximately 45-50 million Sm^3 oil (including NGL and condensate) and approximately 55-80 billion Sm^3 gas. At the same time, the resources in fields and discoveries made prior to 1999 have been adjusted upwards by about 17 million Sm^3 oil and about 73 billion Sm^3 gas. The estimates for total recoverable petroleum resources are approximately 13.2 billion Sm^3 oil equivalents, divided between approximately 6.5 billion Sm^3 o.e. oil/NGL and approximately 6.7 billion Sm^3 o.e. gas.

At the end of 1999, the average recovery rate for oil resources in oil fields in production and under development is estimated to be approximately 44 per cent. This is the same as for 1998, thus ending a continuous trend of annual upward adjustments throughout the 1990s.

In 1999, just under 169 million Sm^3 oil was produced (2.91 million barrels per day), as well as approximately 8 million tonnes NGL/condensate and approximately 48 billion Sm^3 gas net. Gross gas production, including gas for injection, fuel, etc. amounted to about 80 billion Sm^3. Production of oil and NGL/condensate was marginally lower in 1999 compared with the previous year. Lower than expected production is due, among other things, to delayed production start-up for new fields, technical problems on the installations and well problems. In addition, the production regulation involving a 3 per cent cutback which was implemented in May 1998 was continued throughout all of 1999.

Increased recovery

During 1999, the Norwegian Petroleum Directorate continued its focus on the challenges connected with measures to increase recovery. In particular, the use of gas injection was evaluated and viewed in context with overall gas management on the shelf.

Due to the low oil price and cost reductions on the part of the oil companies, the industry cooperation forum FORCE experienced a lower activity level in 1999 than in previous years, and it has proven difficult to establish new cooperation projects. Several seminars were organized under the direction of the forum regarding topics associated with increased recovery. These seminars were of high technical quality and were very well attended.

As of 31 December 1999, the potential increased recovery from the Norwegian continental shelf is estimated at 670 million Sm^3 oil.

In 1999, the Norwegian Petroleum Directorate's increased recovery prize was awarded to Saga as operator of the Snorre field for its testing of alternating injection of foam and water to increase the recovery rate on the field. This was the North Sea's first full-scale test of foam treatment of a reservoir zone, and the world's most comprehensive pilot project based on chemicals.

Development

Four plans for development and operation were approved in 1999: Huldra, Borg, Sygna and Tune. In recent years, the authorities have worked towards facilitating further development of time-critical discoveries and exploitation of existing infrastructure through its consideration of submitted plans and the announcement of blocks in the North Sea.

Investments on the Norwegian shelf remained high in 1999, but will be lower in the next few years as major development projects are completed and new fields that received PDO approval in 1999 will not entail such large investments. Fields that are under consideration for development are generally smaller than in previous years, and several of the largest discoveries are dependent upon gas sales.

The authorities have evaluated the framework conditions for the oil and gas activities in a new Storting White Paper currently under preparation, and have indicated some relief in these conditions. Moreover, the price of oil rose sharply in the last half of 1999, and several plans for development and operation were submitted to the authorities at the end of the year. These plans will be considered in 2000.

New discoveries

A total of five discoveries were made on the Norwegian shelf in 1999, three in the Norwegian Sea and two in the North Sea. 28 exploration wells were completed during the course of the year; 18 wildcat wells and 11 appraisal wells.

Exploration for oil and gas in the deep-water areas of the Norwegian Sea continued in 1999. Saga Petroleum drilled a dry well on Gjallarryggen at a depth of 1,352 metres. So far, this constitutes the record for deep-water drilling operations on the Norwegian shelf. The results of the first round of drilling in deep water in the Norwegian Sea are thus the two gas discoveries 6707/10-1 Nyk and 6305/5-1 Ormen Lange, with gas resources amounting to about 360 billion Sm^3.

Statoil, as operator of well 6507/3-3, made a gas discovery on Dønna terrace which has been named Idun. The discovery is located just to the north of the 6507/5-1 Skarv oil and gas discovery. Saga, as operator of well 6406/2-7, made a new discovery of gas and condensate to the southwest of the Kristin discovery. Although the resource estimates are uncertain, this discovery could make a significant contribution to the development of discoveries on southern Haltenbanken. Shell made a minor oil discovery in well 6407/9-9 near the Draugen field.

Two small oil discoveries were made in the North Sea. Both of the discoveries are located close to infrastructure. One of the discoveries, proven by Statoil in well 9/2-9 S, has already been phased in to the Yme field. Phillips was responsible for the other discovery which was made near Ekofisk in well 2/7-31.

Environment

In general, significant attention is given to environmental issues in the petroleum activities. The Norwegian Petroleum Directorate's paramount goal and result targets reflect the Directorate's responsibility and tasks as regards the environment. The external environment is safeguarded as an integral part of the work aimed at proper management of the Norwegian petroleum resources.

In 1999, the Norwegian Petroleum Directorate, in cooperation with the Norwegian Pollution Control Authority, carried out two supervision audits that were specifically aimed at the operators' safeguarding of the external environment. Forecasts have also been prepared for emissions of CO_2, NO_x, nmVOC, CH_4 and discharges of produced water. Together with the Ministry of Petroleum and Energy, the Directorate has prepared an environmental publication which provides an overview of the environmental aspects on the Norwegian shelf.

The Norwegian Petroleum Directorate aims at ensuring that the industry develops efficient and environmentally friendly solutions that simultaneously ensure good resource utilization and creation of value. In this context, the Directorate has been an active contributor to MILJØSOK in 1999, and has also participated in the authorities' negotiating delegation, which attempted to achieve an agreement with the industry regarding reduction of nmVOC emissions from buoy loading.

Preliminary figures show that CO_2 emissions from the petroleum activities amounted to approximately 9.8 million tonnes in 1999, an increase from 8.3 million tonnes in 1998. CO_2 emissions per produced unit increased by a scant 3 per cent from 1998 to 1999.

The fields' final phase and disposal of installations

We are now standing at the threshold of a new period on the Norwegian shelf in which decisions and measures taken in connection with field shutdowns or other termination of the use of installations will take on increasing importance. The Norwegian authorities have appointed an inter-ministry committee whose task is to prepare a national policy for disposal of installations that have been used in the petroleum activities. A study program has been implemented under the direction of the committee in order to evaluate the disposal of pipelines. This study program was completed in 1999, and a summary report has been prepared. The Norwegian Petroleum Directorate also contributes through its assessments in respect of the decommissioning plans for the individual fields or transportation systems. The Norwegian Petroleum Directorate is also assisting the Ministry of Petroleum and Energy (MPE) in the formulation of a set of guidelines for decommissioning plans.

Data management

In a situation where the volume of information is increasing and information technology is developing at a rapid pace, it is crucial for the efficiency of the petroleum activities that new technology is put to use. The Norwegian Petroleum Directorate is still the project manager of the DISKOS project, which is a joint data solution for 15 oil companies. Emphasis has been placed on reducing unnecessary reporting to the authorities. At the same time, the Norwegian Petroleum Directorate expends significant resources on improving the quality of data that has already been reported. This is to ensure that data incorporated in the Norwegian Petroleum Directorate's many reports, analyses and forecasts is of the best possible quality. The Directorate also places great emphasis on making data that is no longer confidential accessible to the industry in an efficient manner. The Norwegian Petroleum Directorate has participated in various industry measures aimed at standardization of data models and terminology. The Norwegian Petroleum Directorate has also been among the initiators of the industry network SOIL, the use of which is steadily increasing.

Regulatory development

In 1999, the Norwegian Petroleum Directorate continued work on a further simplification and clarification of the regulations. In the new safety and working environment regulations, the number of topical regulations will be reduced from the current 14 to four, within the areas of management, operations, technology and duty of information.

The regulatory reform does not have the objective of tightening the technical requirements placed on the activities, but will continue the current regulation within the frame of a new regulatory structure. The change will make the regulations more accessible and will provide the supervision authorities with more comprehensive and effective management instruments. In addition, the objective is to provide for greater use of recognized industry standards, as well as to improve the predictability in connection with application of the regulations vis-à-vis mobile installations. The plan is for the new regulations to enter into force in 2001.

As a step in the work to transfer as much as possible of the Norwegian Petroleum Directorate's guidelines to industry standards, the Directorate participates actively in international and national standardization work with relevance for safety and the working environment in the petroleum activities.

The Norwegian Petroleum Directorate has continued its annual updates of the regulations in 1999. This work is aimed at ensuring that the regulations are always as practical as possible, and that they are adapted to national and international developments.

The work on developing a so-called “acknowledgement of compliance” system for mobile units has continued in 1999. The Directorate assumes that, among other things, this system can contribute to cost-effective development and operations by preventing unnecessary costs as a consequence of incorrect interpretation and application of regulatory requirements. A pilot project has been carried out in which the system has been applied in connection with an application for consent for activities which included the use of a mobile drilling rig. It is expected that the system will be in force in the latter part of 2000.

Within the area of resource management, the work has been concentrated on preparation of two new Directorate regulations to replace four existing regulations, as well as assistance to the Ministry in the preparation of guidelines under the Petroleum Act and regulations. The regulations will consist of a main regulation that covers all phases of the petroleum activities and a new regulation relating to metering, that will summarize the current regulations relating to fiscal metering and the regulations relating to fuel and flare gas metering for computation of the CO_2 tax. The objective is to develop comprehensive regulations for the resource management area that will contribute to cost-effective management and coordinated action between the petroleum industry and the authorities.

International cooperation

As in previous years, the Norwegian Petroleum Directorate has had significant international involvement in 1999. There has been broad participation in international professional forums and the professional cooperation in the North Sea region has been continued. In addition to the United Kingdom and Denmark, there is now also close cooperation with the Netherlands and the Faroe Islands. The Norwegian Petroleum Directorate enjoys good cooperation with INTSOK, which has established an office in Stavanger. The cooperation with NORAD aimed at assisting developing countries within the field of petroleum management has also laid claim to a significant amount of work in 1999. Similarly, the Norwegian Petroleum Directorate has assisted Petrad in the implementation of a number of seminars and conferences both in Norway and abroad.

Safety and working environment challenges

The industry has implemented significant organizational change processes which have proven to lead to unclear responsibility in important areas. At the same time, the average age of the installations is increasing, with the maintenance problems this entails. In many cases, profitability requirements for the development of marginal fields also leads to challenges in relation to health, safety and environmental requirements.

The companies’ efforts to reduce operating costs were further intensified in 1999, due in part to the low oil price at the beginning of the year. The Norwegian Petroleum Directorate takes a positive view of initiatives to reduce investment and operating costs, if the decision processes leading up to this are properly managed by the companies. The supervision carried out by the Directorate in 1999 aimed at these organizational changes has in many cases revealed that there are inadequate overall evaluations behind the decisions and measures that are implemented. It almost seems as if an element of short-sightedness is entering into the companies’ dispositions. Safety and the working environment face challenging circumstances in organizations where the management horizon is short. Therefore, it is the opinion of the Norwegian Petroleum Directorate that both the industry and the supervision authorities face considerable challenges to ensure that safety and the working environment are maintained and further developed under these new forms of organizing the activities.

Accidents and events

Tragically, there was a serious accident in 1999 that led to one person losing his life. The accident occurred in connection with pipe handling in the derrick. Even though this was the first fatal accident within the Norwegian Petroleum Directorate’s sphere of responsibility since 1995, we must nevertheless underline the fact that the absolute goal is that accidents leading to serious personal injury or death shall not occur. The Directorate’s review of information concerning injuries and undesirable events shows that accidents can be avoided, if the risk associated with the operations is managed in a professional manner.

There were no accidents in 1999 that led to serious damage to the environment, significant material loss or interruption of production.

The frequency of accidents involving personal injury has remained stable at about the same level in recent years. Even though the Directorate does not regard injury rates in the petroleum activities as a whole to be particularly high, it still believes that the injury frequency must be reduced.

The total number of gas leaks was somewhat higher than in 1998, but the proportion of potentially critical leaks was slightly lower. The number of fires and near-fires is higher, but the increase is attributed to fires of an insignificant size. Nevertheless, all fire or near-fire situations present a potential hazard, which leads the Directorate to continue its focus on avoiding fires and near-fires.

Both the number and frequency of reported cases of work-related disease are somewhat lower in 1999 after a period of several years of substantial increases, mainly as a result of improved reporting routines. The decline in the number of cases may be due to the fact that the preventive work is beginning to have a positive effect. However, there are indications that the reporting is still not complete, so that there is still uncertainty related to the trend in this area. In addition to individual suffering, work-related diseases cost both the companies and society a great deal of money. Therefore, it is important that the companies observe good reporting routines so as to contribute to obtaining a better basis for prioritizing efforts in this area.

The Directorate registers, investigates and follows up accidents, injuries and events and uses the results as an important part of the basis for prioritizing measures. These prioritizations provide guidelines for the supervision, regulatory work, information activities and further development of the Directorate’s own expertise.

Information

1999 was the first full year of operation for the Norwegian Petroleum Directorate's publication, "Norwegian Petroleum Diary", which is published in English and Norwegian ("Sokkelspeilet") versions on a quarterly basis. The main objective of the publication is to reflect the activity on the Norwegian shelf and illustrate the role of the Norwegian Petroleum Directorate in the petroleum activities. The Norwegian Petroleum Diary has received an excellent response, and the number of subscribers has doubled since the first issue was published in the autumn of 1998. This extensive interest both at home and abroad shows that the Norwegian Petroleum Diary has been a very good and positive commitment area for the Norwegian Petroleum Directorate.

Organizational development

On the basis of a preliminary project run in 1998, a decision has been made to implement an organization development project called "NPD 2000 and Beyond". Work on the project is scheduled for 1999 and 2000. A program for the entire project was prepared in 1999. External challenges and opportunities were analyzed, work processes were described and a working environment analysis was conducted. Improvement work is underway on the basis of this analysis. The assumptions and premises for the future organization will be concretized during the first half of 2000, after which a new organizational model will be prepared. A new organization can thus be operational at the turn of the year 2000/2001.

Stavanger, 3 April 2000

Gunnar Berge
Director General

1.1 INTRODUCTION

The contribution of the Norwegian Petroleum Directorate within the area of resource management shall be to create the greatest possible value for the society from the oil and gas activities. The Norwegian Petroleum Directorate shall be the central advisory and implementation body of the Ministry of Petroleum and Energy. This requires that the Norwegian Petroleum Directorate at all times has a good overview of development within all phases of the petroleum activities through continuous follow-up.

The petroleum activities represent substantial values for the parties involved. It is of great significance that the professional expertise and knowledge of the authorities are at a high level in order to ensure that social considerations are safeguarded in a satisfactory manner.

1999 has been characterized by extensive oil price fluctuations. At the beginning of the year, the price was about USD 10 per barrel. The implementation of production cutbacks in all OPEC countries except Iraq, as well as measures resulting in lower production in other countries including Norway, contributed to a considerable price increase. In December 1999, the oil price was in the vicinity of USD 26 and at its highest level for the year. The production in the OPEC countries was reduced by 4.7 per cent compared with 1998. During the same period, the world's proven oil reserves were reduced by 1.8 per cent, mainly due to Mexico reducing its reserves by more than 40 per cent.

In Norway, the low oil price increased the expected downturn in investments within the petroleum sector and resulted in dramatic changes in the activity level over the year. In particular, the downturn was noticeable within the area of development, while the exploration activities were not affected to the same degree. However, the number of new discoveries and associated resource estimates were reduced compared with the previous year.

The Norwegian production of oil and NGL in 1999 amounted to about 3.1 million barrels per day, a slight reduction compared with the level of 1998. Norwegian gas exports amounted to 45.5 billion Sm^3 and constituted a 6.8 per cent increase from the previous year. The total remaining discovered resources of oil, NGL, condensate and gas were reduced by 136 million o.e. in 1999. We produced more than we discovered and developed in existing discoveries.

The Norwegian Petroleum Directorate has continued its strong focus on data cooperation with the industry in order to simplify and standardize reporting from the companies and to provide for more efficient exchange of information through better exploitation of computer technology.

An increasing amount of activity has been related to considering plans for decommissioning of fields and disposal of installations. The Norwegian Petroleum Directorate has also participated in a joint ministerial program that is evaluating disposal solutions for pipelines.

1.2 REGULATIONS

The regulatory work within the area of resource management has been focused on preparing two new Directorate regulations as well as to assist the Ministry with its work on preparing guidelines based on the Petroleum Act and regulations.

The two new regulations will replace the previous regulatory provisions on the directorate level within the area of resource management. The regulations consist of one main set of regulations that will cover all phases of the petroleum activities and a new set of regulations relating to metering that will synthesize the current regulations relating to fiscal measurement and the regulations relating to measurement of fuel and flare gas for calculation of CO_2 tax. The regulations are scheduled for an external hearing in 2000 and implementation in 2001.

In addition to the regulations, a set of topical guidelines are being prepared that will provide explanatory guidelines within certain areas. Examples include guidelines for resource classification, guidelines for digital data reporting and guidelines for annual status report for fields in production.

The guidelines for PDO and PIO, prepared under the direction of the Ministry of Petroleum and Energy, have been subject to an external hearing in 1999.

The objective of the regulatory work is to develop unified regulations that contribute to cost-effective management and good interaction between the petroleum industry and the authorities.

1.3 RESOURCE ACCOUNTING

The Norwegian Petroleum Directorate's resource accounting includes an overview of both the original marketable and remaining petroleum volumes on the Norwegian continental shelf. Changes in the resource accounting are inter alia due to new discoveries or that the resource estimates for existing fields and discoveries are adjusted based on new surveys or new production technology. The remaining resources are also reduced by production.

The resource accounting is based on four products: oil, gas, condensate and NGL. As this was done the first time in 1998, it will not be possible to compare reporting from years previous to 1998 for individual products.

1.3.1 RESOURCE CLASSIFICATION SYSTEM

The Norwegian Petroleum Directorate has followed previous practice in the way the discovered resources are classified and entered into the resource accounts. The resources are divided into 12 different classes: Classes 0 to 7 are for the discovered, recoverable resources, Class 8 is for the resources from possible future measures to increase the recovery factor and Classes 9 to 11 for undiscovered resources. The classes are:

Class 0: Reserves where production has ceased
Class 1: Reserves in production
Class 2: Reserves with an approved development plan
Class 3: Resources in the late planning stages (PDO approval within 2 years)

Class 4: Resources in the early planning stages (PDO approval within 10 years)
Class 5: Resources that may be developed in the long term
Class 6: Resources where development is not very likely
Class 7: Resources in new discoveries where evaluation is not complete
Class 8: Resources from potential future measures to increase recovery rate (measures which are not planned, possibly exceeding present-day technology)
Class 9 Resources in prospects
Class 10: Resources in leads
Class 11: Unmapped resources

The main principle in the classification system is that the original recoverable reserves in a field or a discovery shall be classified according to where they are located in the development chain from when a discovery is made, or a new measure to increase the recoverable resources in a field is identified, and up to when the production of the resources is complete. The system takes into account that a field or a discovery may have resources in several classes, i.e., resources of varying maturity in the development chain.

Resources is a generic term used for all types of petroleum volumes.

Reserves comprise recoverable resources in accordance with approved plans for fields in production and for fields under development. In other words, reserves are distributed among the first three classes. A distinction can be made between original recoverable and remaining reserves.

A *deposit* is an accumulation of petroleum in a geological unit, delimited by rocks with structural or stratigraphic boundaries, contact surfaces between petroleum and water in the formation, or a combination of these, so that the petroleum concerned is in continuous pressure communication through fluid or gas.

A *discovery* is a deposit or several deposits together, which through testing, sampling or logging has shown probable mobile petroleum.

A *field* is one or more discoveries together which are covered by an approved Plan for Development and Operation (PDO) or have been granted an exemption from the PDO requirement.

There is only one discovery well for each discovery. This means that wildcat wells which prove resources that are or will be included in the resource estimate for an existing discovery are not considered to be new discovery wells. The

Table 1.3.1 Total petroleum resources on the Norwegian continental shelf

RC		Oil Million Sm^3	Gas Billion Sm^3	NGL Million tonnes	Cond. Million Sm^3	Total o.e. Million Sm^3
	FIELD					
0	Reserves where production has ceased	32	114	4	1	152
1	Reserves in production	3 277	1 484	107	88	4 988
2	Reserves approved for development	199	275	12	35	524
	Total reserves in fields	**3 508**	**1 873**	**122**	**125**	**5 665**
	Reserves sold up to and including 31 Dec. 1999	*2 006*	*626*	*49*	*29*	*2 725*
	Remaining reserves	**1 502**	**1 247**	**73**	**95**	**2 939**
3	Resources in the late planning stages	92	110	8	0	212
4	Resources in the early planning stages	56	755	17	2	836
5	Resources which may be developed over the long term	16	37	0	0	54
6	Resources where development is not very likely	7	2	0	0	9
7	Resources in new discoveries that will be included in other fields	3	0	0	0	3
	Total resources in fields	**173**	**904**	**26**	**2**	**1 113**
	Total recoverable reserves and resources in fields	***3 681***	***2 777***	***148***	***127***	***6 778***
	DISCOVERIES[1)]					
3	Resources in the late planning stages	227	422	30	122	809
4	Resources in the early planning stages	19	361	1	13	394
5	Resources which may be developed over the long term	109	261	5	42	419
6	Resources where development is not very likely	39	62	2	1	105
7	New discoveries	1	39	0	36	76
	Total recoverable resources in discoveries	***396***	***1 145***	***38***	***213***	***1 804***
	OTHER RESOURCES					
8	Resources from potential future measures to increase production	500	500	0	0	1 000
9-11	Undiscovered resources	1 338	2 318	0	0	3656
	Total recoverable potential	***5 916***	***6 740***	***186***	***340***	***13 238***
	Reserves sold up to and including 31 Dec. 1999	*2 006*	*626*	*49*	*29*	*2725*
	Remaining	**3 910**	**6 114**	**137**	**311**	**10 512**

[1)] Discoveries in Resource Classes 3 and 4 also contain resources in higher resource classes; the volumes are therefore not directly comparable with Tables 1.3.3 and 1.3.4.

discovery year is the year the discovery well was temporarily abandoned or completed.

Class 8 comprises the oil and gas volume that could have been recovered in addition to the resources included in the present fields and discoveries if the average future recovery rate is 50 per cent for oil and 75 per cent for gas.

Undiscovered resources comprise both mapped prospects (Classes 9 and 10) and unmapped resources in areas where play models have been defined (Class 11). There is always great uncertainty connected with analyses of undiscovered resources. The size stated for undiscovered resources is the statistical expected value.

1.3.2 RESOURCE ACCOUNTING FOR 1999

The estimated total for original recoverable reserves on the Norwegian continental shelf is 13 238 million Sm^3 oil equivalents (o.e.). 5665 million Sm^3 o.e. (43 %) has already been developed or is approved for development. Of this total, 2725 million Sm^3 o.e. has been produced. This means that there is 2939 million Sm^3 o.e. remaining reserves in fields. In discoveries not yet approved for development, the total recoverable reserves are 1804 million Sm^3 o.e. (appr. 14 %). The undiscovered resources are estimated at 3656 million Sm^3 o.e. (27 %) and resources from potential future measures to increase the recovery factor are estimated at 1000 million Sm^3 o.e. (8 %).

The complete resource accounting for the Norwegian continental shelf is shown in Table 1.3.1.

1.3.3 CHANGES IN 1999

Changes from 1998 to 1999 are shown in Table 1.3.2.

Older fields and discoveries

For older fields and discoveries made before 1998, the oil resources, including NGL resources, have increased by 17 million Sm^3 and the gas resources by 73 billion Sm^3. The changes are based on revisions of the resource estimates for a number of the fields and discoveries. All major changes are described in Chapter 1.3.5.

New discoveries

Five new discoveries were made on the Norwegian continental shelf in 1999. Most of the discoveries have not yet been completed and the preliminary estimate is that the resource growth due to new discoveries will be 45 to 50 million Sm^3 oil (including NGL and condensate) and 55 to 80 billion Sm^3 gas. This is not enough to replace the year's production of oil, but it does cover the year's production of gas.

Production

Recovery of petroleum on the Norwegian continental shelf in 168.6 million Sm^3 oil, 48.3 billion Sm^3 gas, 5.4 million Sm^3 condensate and 3.5 million tonnes NGL. In addition, 0.7 billion Sm^3 gas was flared and 2.6 billion Sm^3 gas was used for fuel.

1.3.4 RESOURCE STATUS

The resource accounting for the Norwegian continental shelf is presented in Table 1.3.1. and the geographical distribution of resources is shown in Figure 1.3.1. The uncertainty of the resource accounting for the petroleum resources is shown in Figure 1.3.2. The resources on the Norwegian continental shelf are divided according to the Norwegian Petroleum Directorate's resource classification system.

Fields where production has ceased, Class 0

Lille-Frigg ceased production in 1999. The number of fields on the Norwegian continental shelf where production has ceased is now ten. The resources in these fields (Resource Class 0) are shown in Table 1.3.3.

Resources in fields which are in production or have an approved plan for development and operation, Classes 1 and 2

As of 31 December 1999, 60 fields on the Norwegian continental shelf have been approved for development, including the ten fields where production has ceased. Troll is considered to be one field, in spite of the fact that it consists of separate developments with different operators. Four plans for development and operation have been approved in 1999; Huldra, Borg, Sygna and Tune.

Eight new fields started production in 1999: Balder, Borg, Gullfaks Sør, Jotun, Oseberg Øst, Rimfaks, Visund, and Åsgard. Of 50 fields in Classes 1 and 2, 46 were producing at the end of the year. Four fields have been approved for development, but have not yet started production (Table 1.3.3).

This year's reporting of resources in fields that may be subject to subsequent development and of resources from measures to increase recovery, follows the practice introduced in 1997 for reporting these resources separately (Table 1.3.3).

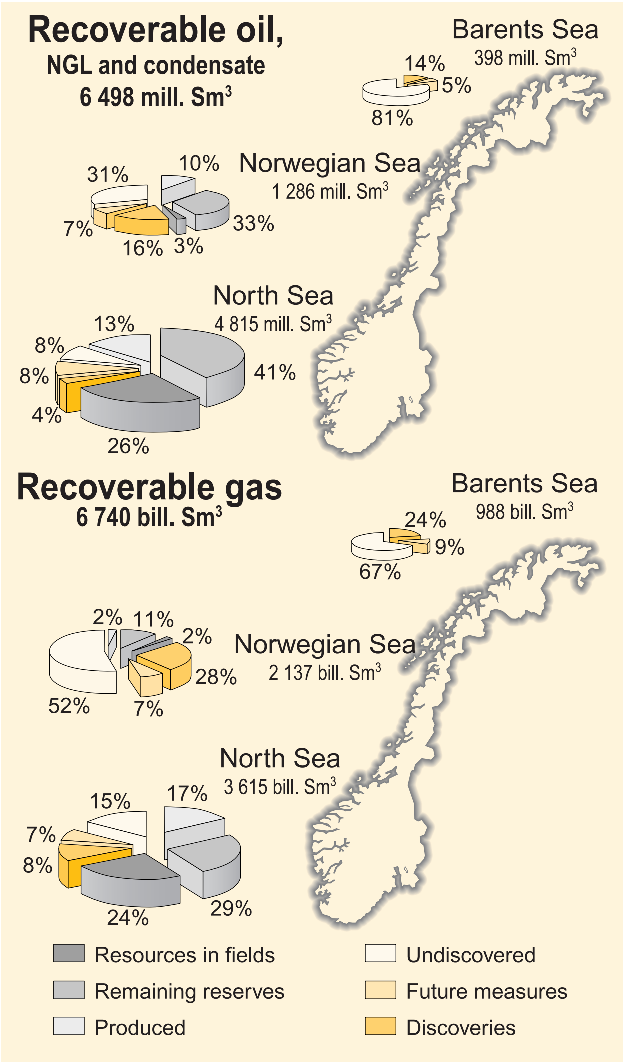
The total recoverable reserves in fields approved for

Table 1.3.2. Changes in the discovered resources

RC		Oil/NGL/Cond. Million Sm^3	Gas Billion Sm^3	Total Million Sm^3 o.e.
0	Technical change for fields where production has ceased	1	2	3
1-2	Reserves in fields approved before 1999	60	122	181
3-6	Resources associated with fields	-61	-52	-113
3-7	Resources in discoveries made before 1999	17	0	18
8	Resources from potential future measures to increase the recovery rate	0	0	0
Total changes		**17**	**73**	**90**
	Net production in 1999, excl fuel	179	47	226
Change in remaining		**-162**	**25**	**-136**

Resource management

Figure 1.3.1
Geographical distribution of petroleum resources on the Norwegian continental shelf



development are 5665 million Sm^3 o.e., divided between 3508 million Sm^3 oil, 1873 billion Sm^3 gas, 125 million Sm^3 condensate and 122 million tonnes NGL (Table 1.3.1). Reserves totaling 1113 million Sm^3 o.e. have been registered as additional resources in fields. These are divided among 173 million Sm^3 oil, 904 billion Sm^2 gas, 2 million Sm^3 condensate and 26 million tonnes NGL.

A total of 2725 million Sm^3 o.e. has been produced, divided between 2006 million Sm^3 oil, 49 million tonnes NGL, 29 million Sm^3 condensate and 626 million Sm^3 gas. The distribution between original recoverable and remaining petroleum is shown in Table 1.3.4.

Resources in discoveries in the late planning stages, Class 3

At the end of the year, there were 22 discoveries in the late planning stages (Table 1.3.5). This includes discoveries which have submitted plans for development and operation for consideration by the authorities or discoveries where the operator has indicated that a plan for development and operation will be submitted and where it is assumed that a plan will be approved by the authorities within two years. The petroleum resources in these discoveries constitute a total of 809 million Sm^3 o.e.

Resources in discoveries in the early planning stages, Class 4

As of the end of the year, there were eight discoveries in the early planning stages (Table 1.3.5). This means discoveries where it is assumed that a plan for development and operation will be approved during the course of 2-10 years. The resource volume constitutes 394 million Sm^3 o.e.

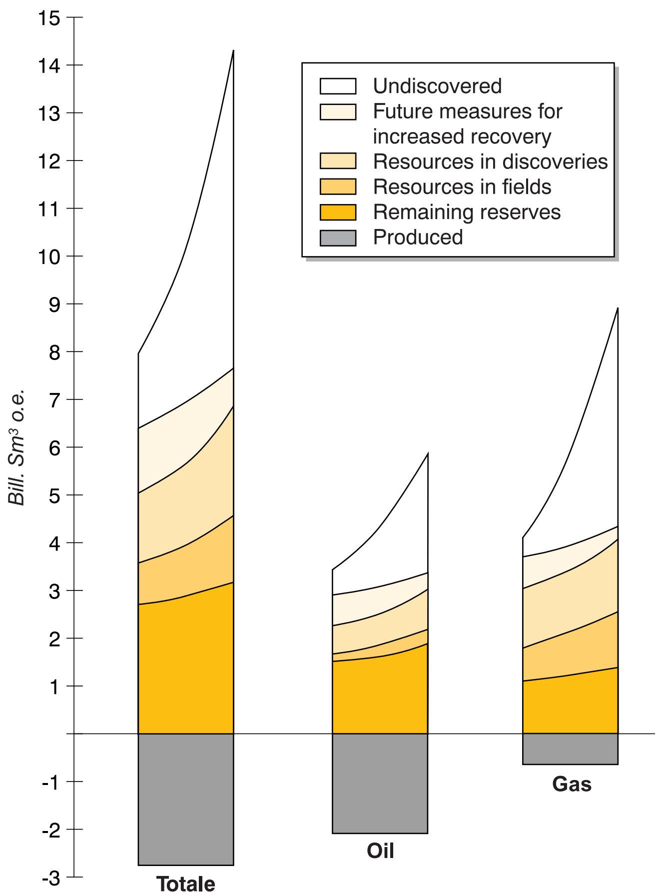
Resources in discoveries which may be developed over the long term, Class 5

As of the end of the year, 49 discoveries (Table 1.3.5) have been identified which the Norwegian Petroleum Directorate believes may be developed over the long term, even though many of the discoveries are currently not considered to be profitable by the licensees. This class also includes some discoveries in relinquished areas, which the Norwegian Petroleum Directorate nevertheless assumes will be re-awarded and developed over the long term. The registered resources amount to 419 million Sm^3 o.e.

Resources in discoveries where development is not very likely, Class 6

As of the end of the year, 44 discoveries have been registe-

Figure 1.3.2
Uncertainty in estmates of petroleum resources



red for which profitable development is not expected without significant changes in technology or price (Table 1.3.5). Most of these discoveries are very small. Some have such poor reservoir properties that they cannot be produced profitably with today's technology and oil price. There is great uncertainty with regard to the resource estimate. However, the Norwegian Petroleum Directorate estimates that technically about 105 million Sm^3 o.e. may be produced from these discoveries.

Resources in discoveries where evaluation is not complete, Class 7

As of the end of the year, four discoveries have been registered in this class. The preliminary estimates for discoveries in Class 7 amount to about 76 million Sm^3 o.e. (Table 1.3.5.). The resources from 6406/2-7 are not included as the evaluation of the discovery has not been completed. These resources come in addition to the registered resources, as this total is still included in the undiscovered resources class.

The are no official estimates for most new discoveries made in 1999, but the Norwegian Petroleum Directorate assumes that the total of these estimates will be about 45-60 million Sm^3 oil and 55-80 billion Sm^3 gas. Of the five new discoveries in 1999, 9/2-9 S and 2/7-31 have been registered as discoveries that will be included in other fields. Discovery 6407/9-9 has been registered in Class 6 and 6507/3-3 in Class 5. Discovery 6406/2-7 has been registered in Class 7, for the time being without a resource estimate. Some discoveries have been reported in fields or in other discoveries (Table 1.3.6).

1.3.5 CHANGES IN RESOURCE ESTIMATES SINCE THE LAST ANNUAL REPORT

A number of adjustments have been made to the estimates for resources and reserves for fields and discoveries during 1999. The total changes are shown in Table 1.3.2. The most important changes are discussed below:

Fields in production and fields approved for development, Classes 1 and 2

Borg

The resources (except long-term test) have been moved from Resource Class 3 to Resource Class 1. The reserves estimate has been increased from 9.4 to 12.6 million Sm^3 oil as a result of a new reservoir model.

Brage

The total oil reserves have been reduced from 54 to 46.7 million Sm^3. This is mainly the result of poorer reservoir properties in the Fensfjord formation than previously anticipated.

Ekofisk

The increase of the oil reserves is the result of reduced residual oil saturation and positive results in flank wells. The NGL estimates have been reduced.

Embla

Increased oil reserves are due to remapping of the field as well as the results from a new well.

Gullfaks Sør

Reduced oil reserves are due to poorer production properties than expected in the Statfjord formation.

Njord

Additional resources in the Tilje formation have been included in the main area of the field (i.e. in the area of the original PDO). The volume of oil in place has been recalculated. The estimate for oil in place in the main area of the Tilje formation has been reduced due to the discovery of gas in the southern central area and new well tests that show that the Tilje formation is thinner on the east flank.

Rimfaks

Increased reserves are due to positive well tests, better production properties and richer gas.

Statfjord

The reserves on the Statfjord field have been adjusted upwards since 1998. This is based on phase-out analyses of the Brent formation, new simulation results from the Statfjord formation, implementation of WAG injection in the Brent group and new information from the North flank.

Valhall

The increase of the reserves on Valhall is due to a new reservoir model with an increase of resources in place. This is based on new well data from 1998 and 1999.

Åsgard

Recoverable oil reserves have been reduced to 64.6 million Sm^3. This is the result of reduced oil recovery on Smørbukk due to more shallow contact and poorer reservoir properties. The recoverable condensate reserves have been increased from 37.4 Sm^3 to 49 million Sm^3. This is the result of increased condensate production on Smørbukk due to changes in the composition of the fluid. Recoverable oil reserves have been increased from 191 billion Sm^3 to 198 billion Sm^3. This is due to increased gas reserves on Midgard.

Discoveries in the late planning stages, Class 3

1/3-3 Tambar

The resource estimate has been adjusted downward due to an assumed change in production strategy.

25/8-10 S Ringhorne

The resource estimate has been adjusted upwards due to wells drilled in 1999.

34/11-1 Kvitebjørn

The resource estimate has been adjusted downwards due to changes in processing preconditions.

Table 1.3.3 Reserves and resources in fields

Reserves where production has ceased (Resource Class 0) 1)

	Oil	Gas	NGL	Condensate	Oil equivalents	
	Mill Sm^3	Bill Sm^3	Mill tonnes	Mill Sm^3	Mill Sm^3	Discovery year
Albuskjell	7.4	15.9	1.0		24.6	1972
Cod	2.9	7.5	0.5		11.1	1968
Edda	4.8	2.1	0.2		7.2	1972
Lille-Frigg		2.3		1.3	3.6	1975
Mime	0.4	0.1			0.5	1982
Nordøst Frigg		11.6			11.7	1974
Odin		29.3			29.3	1974
Tommeliten Gamma	3.9	9.2	0.6		13.9	1978
Vest Ekofisk	12.2	26.9	1.4		40.9	1970
Øst Frigg		9.4		0.1	9.4	1973
Total	**31.6**	**114.3**	**3.7**	**1.4**	**152.1**	

1) Original recoverable reserves in fields where production has ceased is equivalent to the volume delivered. Any remaining recoverable resources are included in appropriate resource class.

Reserves in production or with an approved development plan (Resource Classes 1 and 2)

	Oil	Gas	NGL	Condensate	Oil equivalents	
	Mill Sm^3	Bill Sm^3	Mill tonnes	Mill Sm^3	Mill Sm^3	Discovery year 2)
Balder	26.7				26.7	1967
Borg	12.6	1.6	0.4		14.7	1992
Brage	46.7	2.6	0.7		50.2	1980
Draugen	111.6	0.0			111.6	1984
Ekofisk	417.1	142.2	13.3		576.6	1969
Eldfisk	109.1	50.7	4.2		165.2	1970
Embla	14.5	7.2	0.7		22.5	1988
Frigg		119.8		0.5	120.2	1971
Frøy	5.5	1.6		0.1	7.2	1987
Gullfaks	314.8	21.2	2.0		338.6	1978
Gullfaks Sør	32.8	61.2			94.0	1978
Gullfaks Vest	3.6	0.4			4.0	1991
Gullveig	2.7	2.0			4.8	1995
Gungne		8.4	1.0	3.0	12.6	1982
Gyda	30.7	3.8	1.5		36.4	1980
Gyda Sør	5.6	3.7	0.7		10.2	1991
Heidrun	183.8	19.9	0.1		203.9	1985
Heimdal	6.9	44.6			51.5	1972
Hod	8.2	1.5	0.2		10.0	1974
Huldra 1)		18.7	0.3	7.4	26.4	1982
Jotun	31.1	1.0			32.1	1994
Loke		3.5	0.5	1.2	5.4	1983
Murchison	13.6	0.4	0.4		14.5	1975
Njord	28.4	0.0			28.4	1986
Norne	80.4	15.0	1.4		97.3	1992
Oseberg 4)	337.0	34.0		8.0	378.5	1979
Oseberg Sør 1)	53.5	11.4			64.9	1984
Oseberg Vest	1.6	6.0			7.6	1984
Oseberg Øst	22.8	0.8			23.6	1986
Rimfaks	19.5				19.5	1983
Sleipner Vest		125.5	8.5	27.0	163.6	1974
Sleipner Øst		38.5	9.7	21.3	72.4	1981
Snorre	225.3	9.2	6.0		242.3	1979
Statfjord	569.5	56.4	13.9		644.0	1974
Statfjord Nord	41.6	3.1	0.7		45.6	1977
Statfjord Øst	35.7	5.1	1.0		42.0	1976
Sygna 1)	9.3	0.6			9.8	1996
Tor	27.2	11.6	1.2		40.4	1970
Tordis	29.9	3.1	0.7		33.9	1987
Tordis Øst	5.2	0.5	0.1		5.9	1993
Troll 3)	195.0	653.3	12.7		864.8	1979
Tune 1)	0.0	24.0	0.1	6.1	30.2	1995
Ula	70.0	3.7	2.5		77.0	1976
Valhall	132.3	31.2	4.5		169.4	1975
Varg	4.4				4.4	1984
Veslefrikk	54.5	9.6	1.3		65.8	1981
Vigdis	33.3	2.3			35.7	1986
Visund	48.5				48.5	1986
Yme	9.3				9.3	1987
Åsgard	64.6	198.1	28.0	49.0	348.1	1981
Total	**3476.5**	**1758.9**	**118.2**	**123.5**	**5512.0**	

1) Fields with an approved development plan where production had not started as of 31 December 1999.
2) Discovery year is defined as the year of the oldest discovery well included in the field.
3) Including TOGI.
4) Gas from surrounding fields and discoveries is injected into Oseberg.

Resources in fields

		Oil	Gas	NGL	Condensate	Oil equivalents
		Mill Sm^3	Bill Sm^3	Mill tonnes	Mill Sm^3	Mill Sm^3
Resources in the late planning stages	**Class 3**	91.8	109.7	7.9		212.3
Resources in the early planning stages	**Class 4**	55.5	755.0	17.5	2.3	835.5
Resources which may be developed over the long term	**Class 5**	16.4	37.3	0.5	0.1	54.4
Resources where development is not very likely	**Class 6**	7.1	1.6			8.8
New discoveries	**Class 7**	2.6	0.1			2.7
	Total	**173.4**	**903.7**	**25.9**	**2.4**	**1113.7**

Table 1.3.4
Original and remaining reserves in fields (Resource Classes 1 and 2)

	Original marketable					Remaining				
	Oil	Gas	NGL	ondensate	o.e.	Oil	Gas	NGL	ondensate	o.e.
	Mill Sm^3	Bill Sm^3	Mill tonnes	Mill Sm^3	Mill Sm^3	Mill Sm^3	Bill Sm^3	Mill tonnes	Mill Sm^3	Mill Sm^3
Balder	26.7				26.7	25.7				25.7
Borg	12.6	1.6	0.4		14.7	Reg. on Tordis				
Brage [4]	46.7	2.6	0.7		50.2	12.5	1.1	0.2	-0.1	13.8
Draugen	111.6		0.0		111.6	58.4	0.0	0.0		58.4
Ekofisk	417.1	142.2	13.3		576.6	155.4	29.9	3.6		189.9
Eldfisk	109.1	50.7	4.2		165.2	43.3	19.7	1.1		64.3
Embla	14.5	7.2	0.7		22.5	8.2	5.0	0.4		13.8
Frigg		119.8		0.5	120.2	0.0	7.3	0.0		7.2
Frøy	5.5	1.6		0.1	7.2	0.2	0.4	0.0		0.6
Gullfaks [4]	314.8	21.2	2.0		338.6	54.8	3.5	0.7	-0.6	58.7
Gullfaks Sør	32.8	61.2			94.0	32.0	61.2	0.0		93.2
Gullfaks Vest	3.6	0.4			4.0	1.4	0.4	0.0		1.8
Gullveig	2.7	2.0			4.8	2.3	2.0	0.0		4.4
Gungne [2]		8.4	1.0	3.0	12.6	Reg. on Sleipner [2]				
Gyda [4]	30.7	3.8	1.5		36.4	2.7	-0.9	-0.1		1.7
Gyda Sør [3]	5.6	3.7	0.7		10.2	Reg. on Gyda [3]				
Heidrun	183.8	19.9	0.1		203.9	132.9	18.3	0.1		151.4
Heimdal	6.9	44.6			51.5	0.8	2.2			2.9
Hod	8.2	1.5	0.2		10.0	1.8	0.3			2.1
Huldra [1]		18.7	0.3	7.4	26.4	0.0	18.7	0.3	7.4	26.4
Jotun	31.1	1.0			32.1	30.2	1.0			31.2
Loke [2]	0.0	3.5	0.5	1.2	5.4	Reg. on Sleipner [2]				
Murchison	13.6	0.4	0.4		14.5	0.8	0.1			1.0
Njord	28.4				28.4	22.8				22.8
Norne	80.4	15.0	1.4		97.3	65.4	15.0	1.4		82.2
Oseberg	337.0	34.0		8.0	379.0	71.5	34.0		8.0	113.0
Oseberg Sør [1]	53.5	11.4			64.9	53.5	11.4			64.9
Oseberg Vest	1.6	6.0			7.6	0.5	6.0			6.5
Oseberg Øst	22.8	0.8			23.6	21.9	0.8			22.7
Rimfaks	19.5				17.2	18.4	0.0			16.1
Sleipner Vest [2]		125.5	8.5	27.0	163.6	Reg. on Sleipner [2]				
Sleipner Øst [2, 4]		38.5	9.7	21.3	72.4	0.0	-6.0	0.7	-3.3	-8.4
Snorre [4]	225.3	9.2	6.0		242.3	153.8	5.9	4.0	-0.4	164.6
Statfjord [4]	569.5	56.4	13.9		644.0	72.5	14.6	4.3	-2.6	90.1
Statfjord Nord [4]	41.6	3.1	0.7		45.6	25.4	2.2	0.5	-0.1	28.1
Statfjord Øst [4]	35.7	5.1	1.0		42.0	16.3	3.9	0.7	-0.1	21.0
Sygna [1]	9.3	0.6			9.8	9.3	0.6			9.8
Tor	27.2	11.6	1.2		40.4	6.4	1.1	0.1		7.6
Tordis [4]	29.9	3.1	0.7		33.9	7.2	1.3	0.2	-0.1	8.7
Tordis Øst	5.2	0.5	0.1		5.9	Reg. on Tordis				
Troll	195.0	653.3	12.7		864.8	136.5	588.1	12.7		741.1
Tune [1]		24.0	0.1	6.1	30.2	0.0	24.0	0.1	6.1	30.2
Ula	70.0	3.7	2.5		77.0	10.2		0.2		10.4
Valhall	132.3	31.2	4.5		169.4	70.5	18.8	2.3		92.3
Varg	4.4				4.4	2.7				2.7
Veslefrikk [4]	54.5	9.6	1.3		65.8	18.7	7.9	0.3	-0.1	26.8
Vigdis	33.3	2.3			35.7	21.9	2.3			24.2
Visund	48.5				48.5	47.9				47.9
Yme	9.3				9.3	2.7				2.7
Åsgard	64.6	198.1	28.0	49.0	348.1	60.7	198.1	28.0	49.0	344.2

[1] Fields with an approved development plan where production had not started as of 31 December 1999.
[2] All gas production from the Sleipner area is metered together and is subtracted from the reserves on Sleipner Øst.
[3] All production from Gyda and Gyda Sør is metered together and is subtracted from the reserves on Gyda.
[4] Small negative figures for remaining resources is due to accounting considerations and is caused by lack of correspndence between approximate original recoverable resources and exact production figures.

Table 1.3.5 Resources in discoveries

Resources in the late planning stages (Resource Class 3)

Name of discovery	Oil	Gas	NGL	Condensate	Oil equivalents	
	Mill Sm^3	Bill Sm^3	Mill tonnes	Mill Sm^3	Mill Sm^3	Discovery year [2)]
16/7-4 Sigyn		5.8	2.0	4.7	13.0	1982
2/12-1 Freja	2.0	0.3	0.1		2.4	1987
25/11-15 Grane	112.0	-5.6			106.4	1991
25/11-16	3.6				3.6	1992
25/4-6S Vale	0.0	3.0		3.5	6.5	1991
25/8-10 S Ringhorne	30.4	2.0			32.3	1997
30/6-17	0.3	1.4			1.7	1986
30/6-18 Kappa	1.3	3.1			4.4	1986
30/9-19	2.0	8.8			10.7	1998
34/11-1 Kvitebjørn		49.7	0.4	17.2	67.4	1994
34/7-23 S	2.9	0.4			3.3	1994
34/7-25 S	2.3	0.2			2.5	1996
35/11-4 Fram	32.5	17.2	0.8		50.7	1991
35/8-1		11.7		1.8	13.5	1981
35/8-2		11.7		1.8	13.5	1982
35/9-1 Gjøa	11.6	16.8	0.6		29.1	1989
6406/2-1 Lavrans		62.5	9.4	29.1	103.8	1995
6406/2-3 Kristin		39.1	5.9	42.1	88.8	1997
6407/1-2 Tyrihans [1)]		23.0	4.0	19.4	47.7	1983
6407/6-3 Mikkel	1.6	19.5	4.7	4.6	31.8	1986
7121/4-1 Snøhvit	20.8	176.3	5.7	18.5	223.0	1984
1/3-3 Tambar	5.6	1.5	0.3	0.0	7.5	1983
Total	**228.8**	**448.2**	**33.8**	**142.7**	**863.7**	

[1)] Tyrihans includes resources in Tyrihans Nord and Tyrihans Sør.
[2)] Discovery year is defined as the year of the oldest discovery well included in the field.

Resources in early planning stages (Resource Class 4)

	Oil	Gas	NGL	Condensate	Oil equivalents	
	Mill Sm^3	Bill Sm^3	Mill tonnes	Mill Sm^3	Mill Sm^3	iscovery year
15/5-1 Dagny		5.8	1.0	1.0	8.1	1978
2/4-17 Tjalve	1.3	1.7	0.1		3.1	1992
25/5-3 Skime		4.3		0.9	5.2	1990
25/5-4 Byggve		2.7		0.7	3.5	1991
25/5-5	4.3				4.3	1995
3/7-4 Trym		3.3		0.8	4.1	1990
6305/5-1 Ormen Lange		314.7		5.4	320.1	1997
6507/5-1	18.3	29.9		3.7	51.9	1998
Total	**23.9**	**362.4**	**1.1**	**12.6**	**400.3**	

Resources which may be developed in the long term (Resource Class 5)

	Oil	Gas	NGL	Condensate	Oil equivalents	
	Mill Sm^3	Bill Sm^3	Mill tonnes	Mill Sm^3	Mill Sm^3	iscovery year
1/2-1	0.1				0.1	1989
1/5-2 Flyndre	5.1	1.6			6.6	1974
15/3-1 S	0.0	3.6		15.5	19.1	1975
15/3-4	11.5	5.8			17.3	1982
15/5-2		3.4	0.2	0.2	3.7	1978
15/5-5	6.0	0.3			6.3	1982
15/8-1 Alpha	0.0	4.1	0.5	1.1	5.8	1982
15/9-19 S Volve	5.2	0.8			6.1	1993
16/7-2		1.8	0.3	0.5	2.7	1982
18/10-1	1.2				1.2	1980
2/2-1	0.4	1.1			1.5	1982
2/2-5	2.4	0.0			2.4	1992
2/4-10	2.4	0.0			2.4	1973
2/5-3 Sørøst Tor	0.9	0.3			1.2	1972
2/6-5	0.9	0.0			0.9	1996
2/7-19	3.6	3.5			7.1	1990
2/7-22		0.6			0.6	1990
2/7-29	3.0				3.0	1994
24/12-3 S	4.5	0.1			4.6	1996
24/6-1 Peik	0.0	5.3		1.2	6.5	1985
24/6-2	6.6	1.3			7.9	1998
24/9-3	3.3	0.1			3.4	1981
24/9-5	2.7	0.0			2.7	1994
25/7-5	2.0	0.2			2.2	1997
25/8-4	1.0				1.0	1992

30/10-6	0.0	5.7			5.7	1992
30/7-6 Hild	13.1	33.4			46.5	1978
34/10-23 Gamma	0.0	12.8		1.3	14.1	1985
34/4-5	2.4				2.4	1984
34/7-18	1.7				1.7	1991
35/10-2		1.6			1.6	1996
35/3-2 Agat		43.0			43.0	1980
35/9-3	0.3	0.4			0.7	1997
36/7-2	1.1				1.1	1997
6406/3-2 Trestakk	8.6				8.6	1986
6407/8-2	0.4	1.4			1.8	1994
6506/11-2 Lange	3.5	1.8			5.3	1991
6506/12-3 Lysing	1.2	0.2			1.4	1985
6507/2-2		7.7			7.7	1992
6507/3-1 Alve	1.6	8.5			10.1	1990
6507/3-3 Idun		15.5		0.6	16.1	1999
6707/10-1		38.3			38.3	1997
7/7-2	2.4			0.1	2.5	1992
7120/12-2		10.7			10.7	1981
7120/12-3		4.1			4.1	1983
7121/4-2 Snøhvit Nord		3.5		0.2	3.7	1985
7121/5-2 Beta	3.1	3.3			6.4	1986
7122/6-1	2.6	5.4		0.6	8.6	1987
7124/3-1		2.1			2.1	1987
Total	**104.7**	**233.3**	**1.0**	**21.1**	**360.4**	

Resources where development is not very likely (Resource Class 6)

	Oil	Gas	NGL	Condensate	Oil equivalents	
	Mill Sm^3	Bill Sm^3	Mill tonnes	Mill Sm^3	Mill Sm^3	Discovery year
1/3-1						1968
1/3-6	1.5	0.9	0.1		2.5	1991
1/9-1 Tommeliten Alpha	4.1	8.3	0.3		12.8	1977
15/12-8		1.0		0.5	1.5	1991
17/12-1 Bream	1.0				1.0	1972
17/12-2 Brisling	0.2				0.2	1973
17/3-1						1995
2/2-2		0.9			0.9	1982
2/3-1						1969
2/4-11						1974
2/4-14						1989
2/5-4	7.8	0.4			8.2	1972
2/5-7	2.9				2.9	1984
2/7-2						1971
2/8-17 S	1.0	0.2			1.1	1998
25/10-8	2.7	0.3			3.0	1997
25/2-5 Lille Frøy	3.1	4.9			8.0	1976
25/6-1	1.2				1.2	1986
25/7-2	1.0	1.0			2.0	1990
25/8-9	0.9	0.1			1.0	1997
29/3-1	0.6	1.0			1.6	1986
30/6-14						1984
30/6-16						1985
30/8-3						1998
33/9-6						1976
34/10-40 S		0.6			0.6	1995
34/11-2 S	2.9	4.5			7.4	1996
34/8-7						1993
6/3-1 PI	0.3				0.3	1985
6201/11-1	1.0	0.3			1.3	1987
6204/10-2						1997
6204/11-1		3.4		0.1	3.6	1994
6306/5-1		1.0			1.0	1997
6406/11-1 S	1.0	0.0			1.0	1991
6407/4-1	0.0	0.0				1985
6407/9-9	0.5	1.6		0.1	2.1	1999
6507/7-11 S						1997
7/12-5	1.1				1.1	1981
7/8-3	1.5		1.8		3.9	1983
7119/12-3		4.1			4.1	1983
7128/4-1	0.9	0.1			1.0	1994
7226/11-1	0.6	24.0			24.6	1987
7316/5-1		1.2			1.2	1992
Total	**37.7**	**59.7**	**2.2**	**0.7**	**101.0**	

Resources in new discoveries where evaluation is not complete (Resource Class 7)

	Oil	Gas	NGL	Condensate	Oil equivalents	
	Mill Sm^3	Bill Sm^3	Mill tonnes	Mill Sm^3	Mill Sm^3	Discovery year
2/1-11	0.3				0.3	1997
2/5-11	1.0	0.1			1.1	1997
6406/2-6 Ragnfrid		39.0		36.0	75.0	1998
6406/2-7 Erlend						1999
Total	**1.3**	**39.1**	**0.0**	**36.0**	**76.4**	

Table 1.3.6
1999 discoveries reported as part of other fields or discoveries

Discovery:	Reported in field	Discovery year
2/7-8	Eldfisk	1973
34/10-21	Gullfaks Sør	1984
2/11-10 S	Hod	1994
25/7-3 Jotun	Jotun	1995
25/8-8S Jotun	Jotun	1995
33/9-0 Murchison NØ horst	Murchison	1989
6608/10-4	Norne	1994
30/6-19 Beta Sadel	Oseberg Sør	1986
15/9-20S	Sleipner Øst	1994
15/12-10 S	Varg	1996
30/3-6S	Veslefrikk	1994
34/7-13 Vigdis Vest	Vigdis	1988
34/7-16	Vigdis	1990
34/8-4 S	Visund	1991
9/2-3	Yme	1990
9/2-6 S	Yme	1996
9/2-7 S	Yme	1997
9/2-9 S	Yme	1999
6506/12-1 Smørbukk	Åsgard	1985
6506/12-3 Smørbukk Sør	Åsgard	1985
30/9-10 Oseberg Sør	Oseberg Sør	1990
30/9-13 S Oseberg Sør	Oseberg Sør	1991
30/9-15 Oseberg Sør	Oseberg Sør	1994
30/9-16 K Oseberg Sør	Oseberg Sør	1994
30/9-4 S Oseberg Sør	Oseberg Sør	1985
30/9-5 S Oseberg Sør	Oseberg Sør	1985
30/9-6 Oseberg Sør	Oseberg Sør	1987
30/9-7 Oseberg Sør	Oseberg Sør	1988
30/9-9 Oseberg Sør	Oseberg Sør	1989
Discovery:	**Reported in discovery**	**Discovery year**
16/7-7S	16/7-4 Sigyn	1997
2/7-31	2/7-19	1999
24/9-6	24/9-5	1994
25/8-1 Ringhorne	25/8-10 S Ringhorne	1970
25/8-11 Ringhorne	25/8-10 S Ringhorne	1997
30/3-7 A	30/3-2 Veslefrikk	1998
30/3-7 B	30/3-2 Veslefrikk	1998
30/3-7 S	30/3-2 Veslefrikk	1995
30/7-2	30/7-6 Hild	1975
34/7-29 SR	34/7-23 S	1998
35/11-2	35/11-4 Fram	1987
35/11-7	35/11-4 Fram	1992
35/11-8 S	35/11-4 Fram	1996
36/7-1	35/9-1 Gjøa	1996
6407/1-3 Tyrihans Nord	6407/1- Tyrihans Sør	1984
6507/8-4 Heidrun Nord	6507/7-2 Heidrun	1990
7120/7-1 Askeladd Vest	7121/4-1 Snøhvit	1982
7120/7-2 Askeladd Sentral	7121/4-1 Snøhvit	1983
7120/8-1Askeladd	7121/4-1 Snøhvit	1981
7120/9-1 Albatross	7121/4-1 Snøhvit	1982
7121/7-1	7121/4-1 Snøhvit	1984
7121/7-2 Albatross Sør	7121/4-1 Snøhvit	1986

34/7-23 S
The resource estimate has been adjusted downwards as a result of formation strength tests.

35/11-4 Fram
The resource estimate has been adjusted downward due to a changed development concept.

35/9-1 Gjøa
The resource estimate has been adjusted downward due to a changed development concept.

6406/2-1 Lavrans
The resources have been adjusted upwards as a result of well drilled in 1999.

6407/6-3 Mikkel
The reserves estimate has been increased somewhat as a result of new studies.

7121/4-1 Snøhvit
The resource estimate has been adjusted upwards based on new studies.

Discoveries in the early planning stages, Class 4

6507/5-1
The resource estimate has been adjusted downwards as a result of wells drilled in 1999.

UNITS OF MEASUREMENT FOR OIL AND GAS

Oil and gas are often stated in volumetric units under defined ISO standard conditions (temperature = 15°C and pressure = 1.01325 bar). Oil volumes are stated in million Sm^3 (10^6 Sm^3) and gas volumes in billion Sm^3 (10^9 Sm^3).

Oil and gas volume units are converted to oil equivalents when adding or comparing oil and gas resources and when an exact figure for the quantity is not needed.

The conversion to *oil equivalents* is based on the amount of energy that is released during oil and gas combustion.

As of 1 January 1996 the Norwegian Petroleum Directorate states the total petroleum resources in Sm^3 oil equivalents (Sm^3 o.e.). We will therefore use the following conversion factors when we add up or compare oil and gas quantities:

1 000	Sm^3 gas equals:	1 Sm^3 o.e.
1	Sm^3 oil equals:	1 Sm^3 o.e.
1	tonne NGL equals:	1,3 Sm^3 o.e.

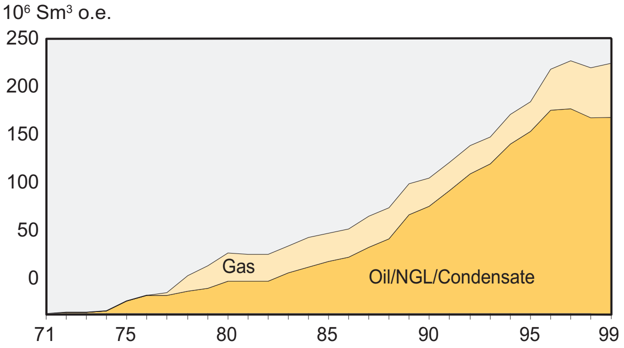
Conversion from the NGL weight unit to Sm^3 *oil equivalents* is somewhat more uncertain as the composition of the light hydrocarbon components may vary quite a bit from field to field. We have elected to use a fixed conversion factor of 1.3 from tonnes NGL/condensate to Sm^3 o.e.

Table 1.4.1
Production in million Sm^3 oil equivalents

1998	Production			Consumption		Marketable products			
	Oil	Gas	Cond.	Gas Flare	Gas Fuel	Oil	Gas	NGL/ Cond.	Total
Balder	0.881			0.016		0.881			0.881
Brage	3.827	0.321		0.007	0.062	3.799	0.157	0.133	4.068
Borg	0.192	0.025							
Draugen	12.139	0.640		0.004	0.060	12.139			12.139
Ekofisk Area	16.191	3.288		0.028	0.356	15.660	3.379	0.596	19.635
Embla	0.804	0.258				0.702	0.251	0.063	1.016
Frigg Area	0.513	0.665	0.079	0.004	0.030	0.506	0.622	0.020	1.148
Gullfaks	17.130	2.447		0.044	0.272	17.130	0.913	0.158	18.201
Gullfaks Vest	0.147	0.018				0.147			0.147
Gullfaks Sør	0.754	0.154				0.754			0.754
Gullveig	0.347	0.178				0.347			0.347
Gyda (incl. Gyda Sør)	2.063	0.763		0.002	0.032	1.502	0.456	0.176	2.134
Heidrun	12.540	2.140		0.010	0.125	12.449	0.653		13.102
Heimdal		0.833	0.136		0.029	0.117	0.821		0.938
Hod	0.137	0.019			0.001	0.130	0.018	0.004	0.152
Jotun	0.863	0.039		0.028		0.863	0.010		0.873
Murchison	0.272	0.048		0.003	0.014	0.252	0.001	0.006	0.259
Njord	3.525	1.742		0.012	0.060	3.522			3.522
Norne	8.305	1.834		0.016	0.115	8.305			8.305
Oseberg	19.413	8.575		0.023	0.248	19.435			19.435
Oseberg Vest	0.045	0.116			0.004				
Oseberg Øst	0.914	0.085		0.017	0.011	0.911			0.911
Rimfaks	1.107	0.283				1.107			1.107
Sleipner Area		15.592	9.017	0.012	0.260		11.151	9.679	20.830
Snorre	10.116	1.437		0.036	0.133	0.9398	0.314	0.559	10.271
Statfjord	12.519	6.851		0.091	0.405	12.519	2.141	1.053	15.713
Statfjord Nord	3.462	0.264				3.393	0.158	0.089	3.640
Statfjord Øst	4.227	0.596				4.236	0.246	0.092	4.574
Tordis	2.909	0.299		0.002	0.042	4.421	0.307	0.207	4.935
Tordis Øst	1.320	0.135					0.012	0.010	0.022
Troll Area	12.585	26.546	0.642	0.022	0.122	12.909	25.461		38.370
Ula	1.517	0.142		0.003	0.048	1.457		0.052	1.509
Valhall	5.600	1.085		0.011	0.090	5.310	1.035	0.256	6.601
Varg	1.743	0.291		0.035	0.005	1.743			1.743
Veslefrikk	1.892	0.508		0.042	0.027	1.900	0.112	0.069	2.081
Vigdis	5.107	0.358				5.109			5.109
Visund	0.630	0.189		0.048	0.026	0.628			0.628
Yme	1.593	0.063		0.021	0.011	1.484			1.484
Åsgard	3.901	1.970		0.125	0.055	3.901			3.901
Total 1999	170.693	80.246	9.262	0.662	2.647	168.598	48.257	9.930	226.786
Total 1998	170.039	72.594	8.235	0.463	2.926	168.950	44.190	9.963	223.103
Total 1997	178.388	70.365	8.772	0.411	3.034	175.868	42.949	10.729	229.547
Total 1996	177.282	59.456	7.253	0.448	2.833	175.496	37.407	9.242	222.144
Total 1995	157.926	47.193	5.922	0.409	2.640	156.622	27.814	8.439	192.874
Total 1994	147.674	45.393	4.588	0.364	2.630	146.282	26.842	7.143	180.267
Total 1993	133.770	41.576	1.280	0.340	2.544	131.843	24.804	4.156	160.803
Total 1992	125.936	42.444	0.573	0.309	2.449	123.999	25.834	3.369	153.202
Total 1991	110.513	39.717	0.563	0.356	2.257	108.510	25.027	3.312	136.849
Total 1990	96.844	37.065	0.521	0.556	2.132	94.542	25.479	3.420	123.442
Total 1989	88.266	39.320	0.547	0.474	2.013	85.983	28.738	3.327	118.048
Total 1988	66.882	36.302	0.588	0.336	1.818	64.723	28.330	3.303	96.356
Total 1987	58.538	34.499	0.577	0.434	1.443	56.959	28.151	2.813	87.923
Total 1986	50.579	33.924	0.355	0.258	1.311	48.771	26.090	2.630	77.491

Resource management

Figure 1.4.1
Oil and gas production on the Norwegian shelf 1971-1999



1.4 PRODUCTION OF OIL AND GAS

The production of oil and gas on the Norwegian continental shelf amounted to 226.8 million Sm³ o.e. in 1999. Production amounted to 223.1 million Sm³ o.e. in 1998. Production details are presented in Table 1.4.1 and in Figure 1.4.1. Table 1.4.1 shows the Norwegian share of production for Statfjord, Frigg and Murchison.

1.5 PETROLEUM ECONOMY

1.5.1 EXPLORATION COSTS

In 1999, 22 exploration wells were spudded, while the number of exploration wells in 1998 was 26. Fifteen wildcat wells and seven appraisal wells were spudded in 1998. Corresponding figures for 1998 were 17 and 9. On average over the period from 1966-1999, the number of spudded wildcat and appraisal wells has been 21 and 8, respectively.

Figure 1.5.1 shows the costs of exploration and planning activities from and including 1980. The costs include exploration drilling, general surveys, discovery evaluations and administration. According to figures reported to the Norwegian Petroleum Directorate, the total exploration costs in the years 1980-1999 amount to approximately 161 billion 1999-NOK.

Exploration and planning costs for 1999 divided among the various types of costs are shown below. The figures are based on data reported by the operating companies. The same figures are used as a basis for Figure 1.5.2, which shows the cost distribution in per cent.

Exploration and planning costs	**Million NOK**
Exploration drilling	2887
General surveys	580
Discovery evaluations	538
Administration[1]	1121
Total	**5126**

[1]) Administration costs include area fees

In 1999, the share of exploration costs related to exploration drilling was 57 per cent, while the corresponding figure for 1998 is 56 per cent. The share of costs related to general surveys is 11 per cent in 1999 compared with 15 per cent in 1998. General surveys include inter alia acquisition of seismic data.

Figure 1.5.3 shows the average drilling costs per exploration well, i.e. wildcat and appraisal wells. In 1999, drilling was carried out at a cost of around NOK 2.9 billion, and the cost per well is estimated to be about NOK 131 billion. This is a relative reduction compared with 1998 when drilling costs per well were about NOK 165 million.

Figure 1.5.1
Annual exploration and planning cost

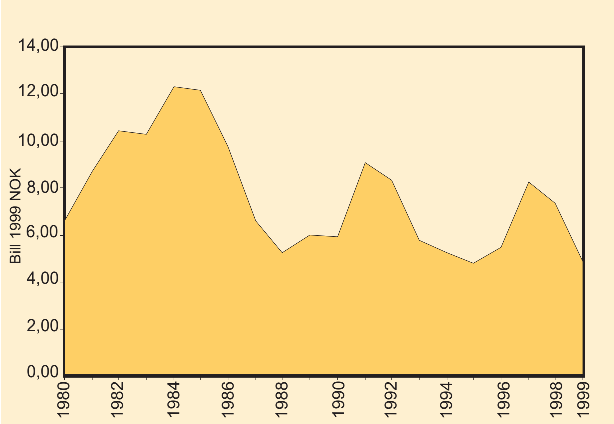


Figure 1.5.2
Percentage distribution of the cost

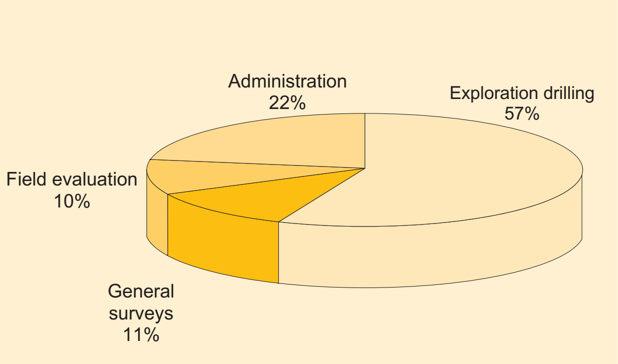


Figure 1.5.3
Average drilling cost per exploration well

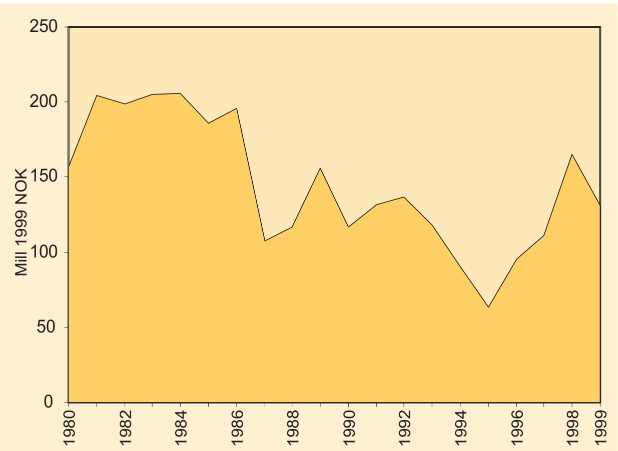
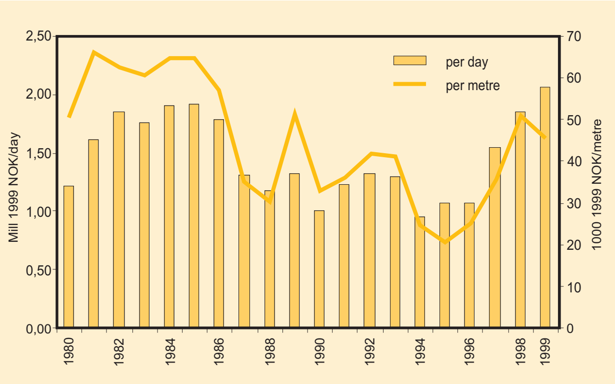


Figure 1.5.4
Average drilling cost per day
and per metre drilled in the years 1980 - 1999



However, the total drilling costs have declined since 1998, when drilling was carried out for about NOK 4.3 billion. Figure 1.5.4 shows the average drilling costs per day and per metre drilled in the years 1980-1999.

1.5.2 THE STATE'S DIRECT FINANCIAL INTEREST

The State's Direct Financial Interest (SDFI) in the petroleum activities was established with effect from 1985. Statoil's ownership interests were then split into a financial interest to Statoil and a direct financial interest to the state. Up until the 14th licensing round, both Statoil and SDFI were normally awarded ownership interests in all production licenses that were awarded. From and including the 15th round, blocks were awarded without SDFI participation. In addition, interests were awarded to SDFI without Statoil receiving corresponding interests. Statoil is responsible for the operational and financial follow-up of the state's direct interest. An important consideration in the formulation of petroleum policy has been that the state shall collect a significant share of economic rent in the oil activities. SDFI, together with the petroleum taxation system and dividends from Statoil, comprise the state's revenues from the petroleum activities. The SDFI arrangement entails that the state pays a share of the investments and operating costs in a project corresponding to its interest. In the same way as all other licensees, the state will receive its corresponding share of the production and revenues. As a consequence of significant ownership interests in the vast majority of licenses, SDFI is the largest investor on the Norwegian shelf, and is represented with a considerable resource volume in the exploration, development and operations phases.

1.5.3 CRUDE OIL MARKET

Global oil production in 1999 (excluding NGL) is estimated to be about 64.6 million barrels per day (Source: Oil and Gas Journal (OGJ) 20 December 1999). This is equivalent to 3.7 billion Sm^3 per year and means a reduction of 1.3 per cent from 1998. The production from the OPEC countries was reduced by 4.7 per cent, from 27.8 million barrels per day in 1998 to 26.5 million barrels per day in 1999. The production was reduced in all OPEC countries except Iraq. The production outside of OPEC was also reduced by 0.8 per cent, or approximately 0.3 million barrels per day. In particular, production was reduced in the USA, Canada and Mexico, while it increased in Brazil, the United Kingdom and Denmark for example.

Norwegian oil production was approximately 2.9 million barrels per day in 1998, accounting for 4.6 per cent of global production. OPEC's market share was just over 41 per cent, down one per centage point from 1998.

According to OGJ, the world's proven oil reserves at the end of 1999 were 16.5 billion Sm^3, which is a reduction of 2,9 billion Sm^3 during the year (-1.8 %). This is the first time since 1992 that OGJ has adjusted the total reserves estimate downwards. Mexico is the cause of the major share of the adjustment, as it adjusted its reserves downward by 3.1 billion Sm^3, corresponding to more than 40 per cent. The USA also shows a significant reduction (-7 %). Based on the resource estimates, the largest oil-producing area in the future will be the Middle East. This area contains 66.5 per cent of the global oil reserves (+1,5 %). OPEC's share is 79 per cent.

At the beginning of 1999, the oil market was characterized by low prices and large inventories. In the middle of February, the oil price dipped below USD 10 per barrel, corresponding to about NOK 75. After that, the oil price rose due to expectations concerning additional production cutbacks in the OPEC countries and the cutbacks were adopted on 23 March. The oil price continued to increase during the year. The price reached its highest level, about USD 26, in December. The most important factors behind the price increase are that OPEC implemented a significant production cutback and that economic growth in Asia was picking up.

This resulted in an average, volume-weighed norm price of USD 18 per barrel for oil produced in Norway; corresponding to NOK 141. As a comparison, the average price in 1998 was about NOK 96 per barrel (about USD 12.7 per barrel) for oil produced in Norway.

1.5.4 NATURAL GAS MARKET

In 1999, Norway exported gas to the United Kingdom, Germany, the Netherlands, Belgium, France, Spain, Austria and Czechia.

In 1999, export from Norway constituted 45.5 billion Sm^3, an increase of about 2.9 billion Sm^3 (6.8 %) gas compared with the previous year. The average energy content of the exported gas was 40.3 megajoule per cubic metre.

The first gas sales were primarily based on depletion of accessible reserves in the individual fields. Norway entered a new era as a gas supplier on 1 October 1993 when deliveries under the Troll agreements (TGSA) got underway. These are sales contracts which offer the customers fixed annual volumes, where also other fields than Troll may provide deliveries. In connection with the Troll agreements, the authorities have established the Troll commercial model, which provides opportunities for the sale of associated gas and smaller gas fields.

Resource management

Organization of Norwegian gas sales

Since 1986, the sale of Norwegian gas has been coordinated by a Gas Negotiation Committee (GFU) under the direction of Statoil and with participation by Norsk Hydro and Saga. Other companies are also involved in the negotiation of gas sales contracts. In 1993, the authorities set up the Gas Supply Committee (FU). This committee, which consists of the largest gas owners on the Norwegian continental shelf, shall have an advisory role vis-à-vis the Ministry of Petroleum and Energy in questions related to development and management of gas fields and transportation systems for gas.

Existing commitments

Field contracts

The fields which currently deliver under field contracts are Statfjord, Gullfaks, as well as fields in the Frigg and Ekofisk areas. Production from these fields is now in the decline phase. Gas deliveries from the Ekofisk and Frigg areas started in 1977, from Statfjord in 1985, from Heimdal in 1986 and from Gullfaks in 1987. The gas from the Frigg area is delivered to the United Kingdom, while the other fields deliver to buyers on the Continent.

Troll gas sales agreements from 1986 (TGSA)

The TGSA agreements were signed in 1986 between the Troll licensees and buyers on the Continent. The buyer countries are Germany, the Netherlands, Austria, France, Belgium and Spain. At plateau (2005), the Troll agreements comprise 44.7 billion Sm³ per year, including exercised purchase options.

Newer commitments

An agreement with the Polish company POGC was signed in 1999. In addition, several agreements regarding short-term sales were signed in 1998 and 1999 with time frames ranging from one day to several months.

Potential new sales

Over time, it is expected that Norway's total gas sales may reach approx. 85 billion Sm³ per year. The estimate is based on the buyers ordering a volume identical to the »take or pay" obligations under the various contracts. Figure 1.5.5 shows committed and potential new sales. Committed volumes are divided between field contracts, allocated supply contracts and non-allocated supply contracts. The Ministry of Petroleum and Energy allocates volumes after consultation with the Norwegian Petroleum Directorate and the Gas Supply Committee. In addition, plans have been presented regarding construction of a power station in Skogn in Nord-Trøndelag. Planned gas consumption is 1.1 billion Sm³ per year.

Use of gas in Norway

In 1995, the Ministry of Petroleum and Energy presented a separate report to the Storting regarding the use of gas in Norway. The Storting report presents the government's objectives and the possibilities for use of natural gas in Norway.

The most important Norwegian gas market is the market for injection gas on the continental shelf. The gas is injected in order to achieve increased oil recovery. The largest

Figure 1.5.5
Committed and potential future sales of gas.

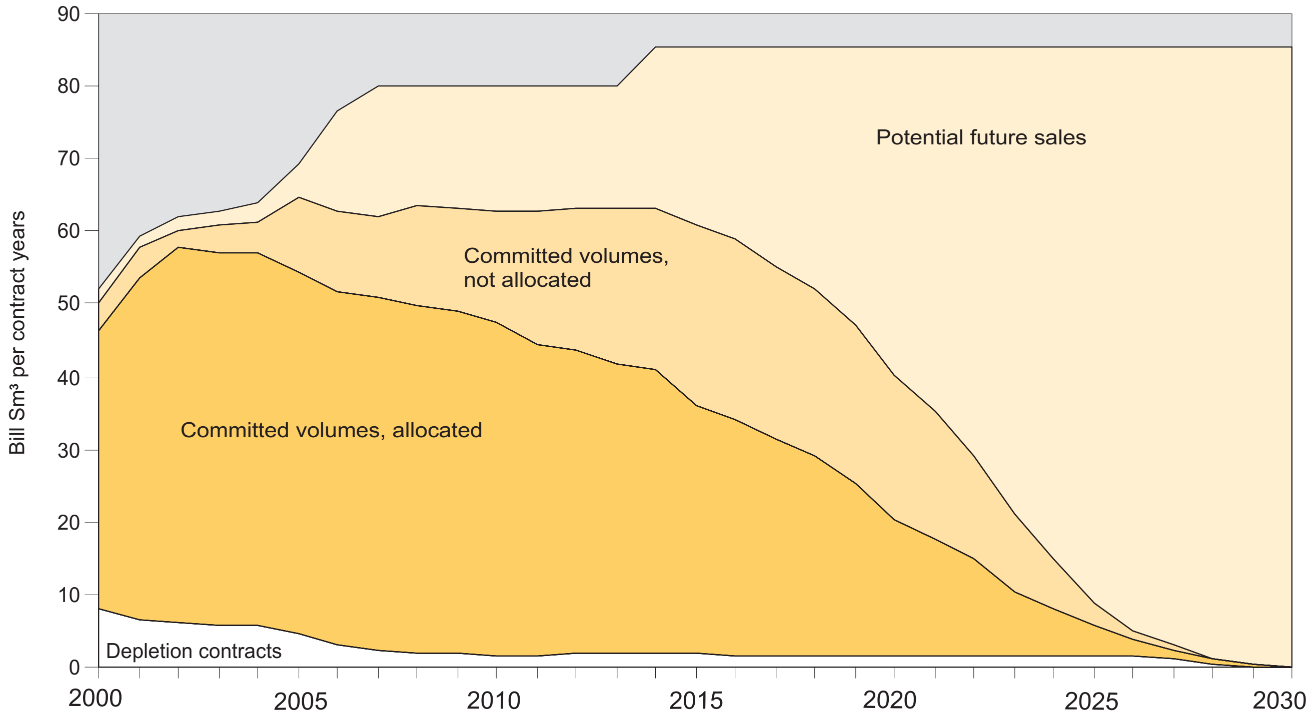
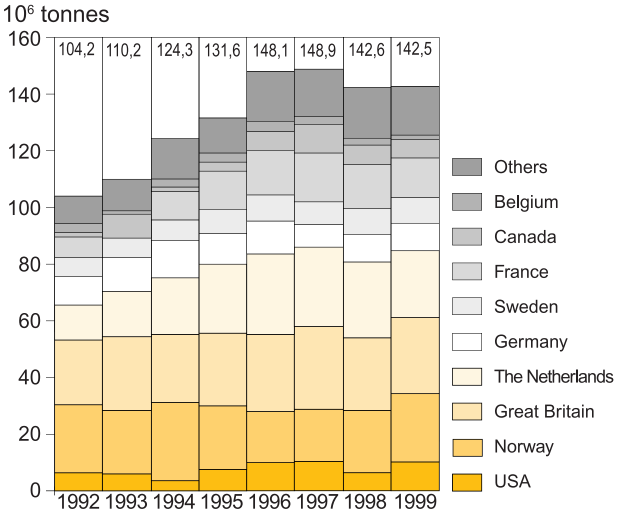


Figure 1.5.6
Sales of crude oil from the Norwegian shelf



consumers are Oseberg, Åsgard, Statfjord, Gullfaks, Njord, Snorre and Visund. Gas is also the most important source of energy for operation of field and transportation systems. Primarily gas produced from the field itself is used for these purposes. In 1999, a total of 28.6 billion Sm³ gas was used for injection and 2.65 billion Sm³ was used as fuel on the shelf.

Gas has been landed in Norway since Statpipe began operations in 1985. The gas is landed at Kårstø in northern Rogaland, at Kollsnes in Hordaland and Tjeldbergodden in Møre og Romsdal.

In northern Rogaland, an agreement has been signed regarding smaller deliveries to the distribution company Gasnor. All of Gasnor's customers have previously used fuel oil as a source of energy. Deliveries commenced in 1994. The company Naturgass Vest has started developing a distribution network for natural gas from Kollsnes in Øygarden. The first construction stage was a high-pressure gas line from the Kollsnes gas plant to Kollsnes industrial park completed in the autumn of 1999. Production of compressed natural gas for use in busses and other motor vehicles will be established with a planned start-up of three filling stations in February 2000. Tie-ins to the first the industrial customers are also planned for February 2000.

In 1994, Statkraft, Statoil and Norsk Hydro set up a joint company, Naturkraft. Naturkraft received a licence for development and operation of two gas power plants, but the projects are not currently profitable due to stringent purification requirements. The plan is for the power plants to be established at Kårstø and Kollsnes. Total consumption of gas in the gas power plants will be 0.9 billion Sm³ gas per year.

1.5.5 SALE OF PETROLEUM FROM THE NORWEGIAN CONTINENTAL SHELF

In 1999, 142.5 million tonnes of crude oil were sold from the Norwegian continental shelf. This represents a decrease of 0.1 per cent compared with 1998. The United Kingdom was the largest recipient with 18.9 per cent of the shipments, Norway received 17.1 per cent, the Netherlands 16.7 per cent, France 9.8 per cent and Germany 6.7 per cent. In 1998, Norway received 15.5 per cent. Figure 1.5.6 shows crude oil sales distributed by country in the period 1981-1999. Up to 1988, Belgium and Canada are included in the group "others".

Sale of NGL (including condensate) from the Norwegian continental shelf in 1999 reached 7.7 million tonnes. This is 0.5 million tonnes more than in 1998. Figure 1.5.7 shows the sale of crude oil and NGL in 1999 distributed by licensees.

Norway exported 45.5 billion Sm³ gas in 1999. This is an increase of 6.8 per cent compared with 1998. 16.1 billion Sm³ was sold to Germany, 1.4 billion Sm³ to the United Kingdom, 12.9 billion Sm³ to France, 5.2 billion Sm³ to the Netherlands, 5.6 billion Sm³ to Belgium, 2.5 billion Sm³ to Spain, 1.3 billion Sm³ to Czechia and 0.5 billion Sm³ to Austria, see Figure 1.5.8.

Figure 1.5.7
Sales quantities of oil/NGL (excl. condensate) per licensee in 1999

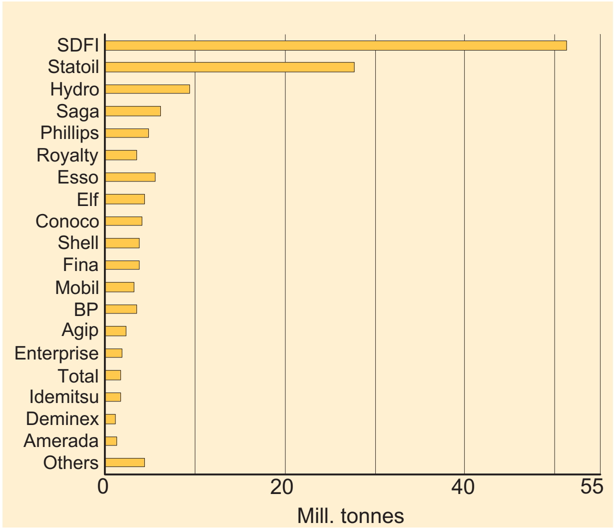
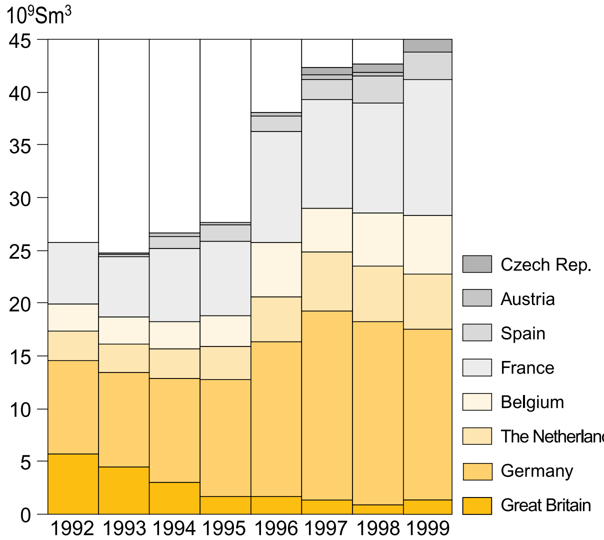


Figure 1.5.8
Sales quantities of gas per country



1.5.6 PRODUCTION ROYALTY

The Norwegian Petroleum Directorate has been delegated the responsibility for collection of royalties from petroleum production. Production royalty is calculated according to the provisions of the Petroleum Act. The basis for calculation of the royalty is the value of the produced petroleum at each production area's loading point. As it is not customary to calculate the price of petroleum products at the loading point, in practice the calculation basis applied is the difference between the gross sales value and the costs incurred between the taxation point and the point of sale.

No production royalty shall be paid on production from deposits where the development plan is approved or requirements for a plan for development and operation terminate after 1 January 1986, cf. Section 4-9 of the Petroleum Act.

Interpretation and enforcement of the current laws and regulations in connection with calculation of royalties include issues of a legal, economic, processing and metering nature.

From 1 January 1992, the royalty rate for gas was set at nil, cf. Section 31 of the Petroleum Regulations. This means that, as of that date, royalty is only to be levied on oil.

Figure 1.5.9
Royalties paid 1990-1999

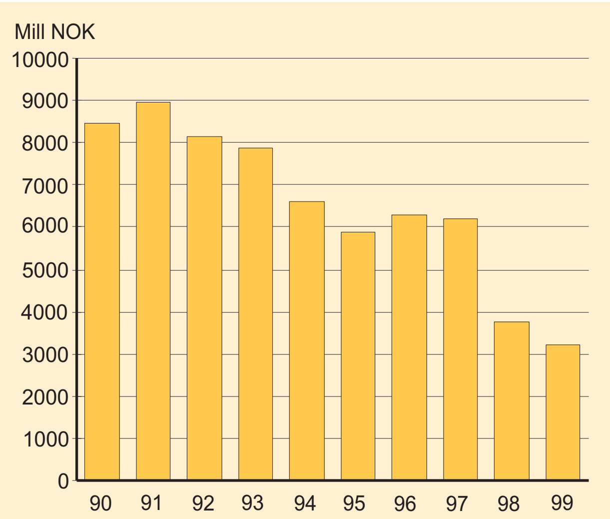
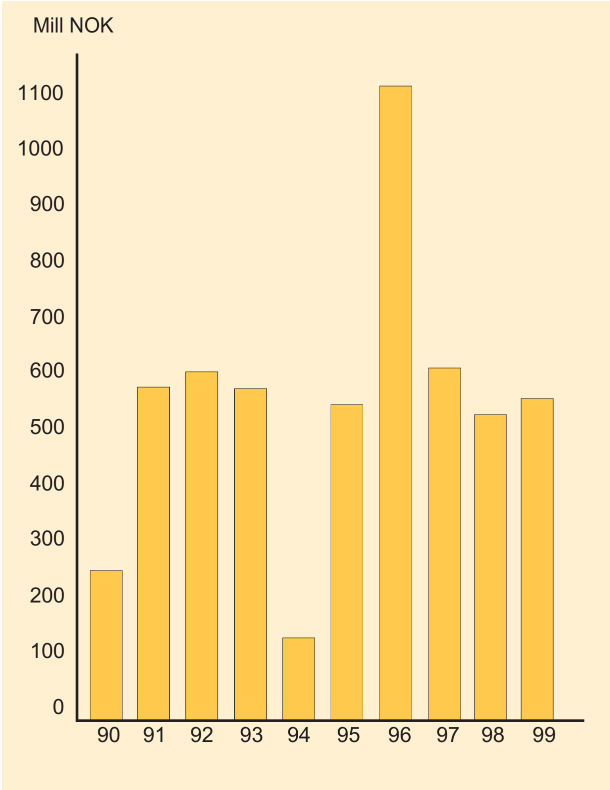


Table 1.5.1
Total royalty paid in 1998 and 1999 (million NOK)

Product	Field/area	1998	1999
Oil	Ekofisk area, Ula and Valhall	1 247.7	563.9
"	Statfjord	1 248.7	1 312.1
"	Murchison	19.5	0.8
"	Heimdal	10.8	0.7
"	Oseberg	662.5	817.7
"	Gullfaks	524.8	518.9
NGL	Ekofisk area	33.2	3.7
"	Valhall	5.7	3.6
"	Ula	1.2	0.1
"	Murchison	0.8	0.4
Total		**3 754.9**	**3 221.9**

Figure 1.5.10
Area fees 1990-1999



In Report No. 1 (1999-2000) to the Storting, the Government has proposed a gradual reduction of the production royalty starting 1 January 2000. As early as 1 January 2000, production royalty will not be levied on the fields Heimdal, Tor and Murchison. Production royalty will be gradually reduced over three years for the fields Statfjord, Ula and Valhall and over six years for the fields Oseberg and Gullfaks.

Since, on some fields, oil and NGL are a single product at the loading point and the NGL is separated at a later stage, royalty will be paid on the NGL for these fields. On the other hand, royalty will not be levied on NGL in those fields where NGL is part of the gas at the loading point.

Total royalty

In 1999, licensees on the Norwegian shelf paid royalties totaling NOK 3,221,857,609 to the Norwegian Petroleum Directorate. Table 1.5.1 shows the breakdown for the various petroleum products for 1998 and 1999. Figure 1.5.9 shows paid production royalty for the period 1990 - 1999.

Production royalty on oil

In 1999, NOK 3,214,106,169 was paid in royalties for oil from the Ekofisk area (the Tor field), Ula, Valhall, Statfjord, Murchison, Heimdal, Oseberg and Gullfaks, see Table 1.5.2. The royalty on oil is usually taken out in oil, but the Ministry of Petroleum and Energy has determined that the royalty on oil from Heimdal shall be taken out in cash as from 1 April 1993. Sale of the State's royalty oil is the responsibility of Statoil. Payment from Statoil to the Norwegian Petroleum Directorate is on a monthly basis. Settle-

Resource management

Table 1.5.2
Royalty paid on oil (NOK)

Field/area	1st half	2nd half	Total 1999
Ekofisk area, Ula and Valhall	125 958 967	437 916 366	563 875 333
Statfjord	502 448 720	809 622 307	1 312 071 027
Murchison	394 081	447 849	841 930
Heimdal	26 395	665 930	692 325
Oseberg	343 493 262	474 236 375	817 729 637
Gullfaks	230 636 211	288 259 706	518 895 917
Total	**1 202 957 636**	**2 011 148 533**	**3 214 106 169**

Table 1.5.3
Royalty paid on NGL (NOK)

Field/area	1st half	2nd half	Total 1999
Ekofisk area			
Phillips Group	3 083 351	625 309	3 708 660
Amoco Group (Tor)	833	-	833
Total Ekofisk area	3 084 184	625 309	3 709 493
Valhall	2 894 830	656 827	3 551 657
Ula		88 027	88 027
Murchison	113 238	289 025	402 263
Total all fields	**6 092 252**	**1 659 188**	**7 751 440**

ment is at the norm price stipulated by the Petroleum Price Council. The received quantity of royalty oil has been reduced by as much as 32 per cent in 1999, partly due to lower production from those fields where there is a royalty, but also because of the discontinuance of the royalty on Ekofisk (Production Licence 018) from and including 7 August 1998 in connection with the new processing facility (Ekofisk II) being put into operation. Lower production has also resulted in a reduced royalty rate on some fields. But the significant reduction in the quantity of royalty oil received has partially been compensated by higher oil prices in 1999 compared with 1998, so that the total royalty paid has been reduced by 13.5 per cent.

Production royalty on NGL

In 1999, NOK 7,751,440 was paid in royalties for NGL. Table 1.5.2 shows payments divided semi-annually per company/group.

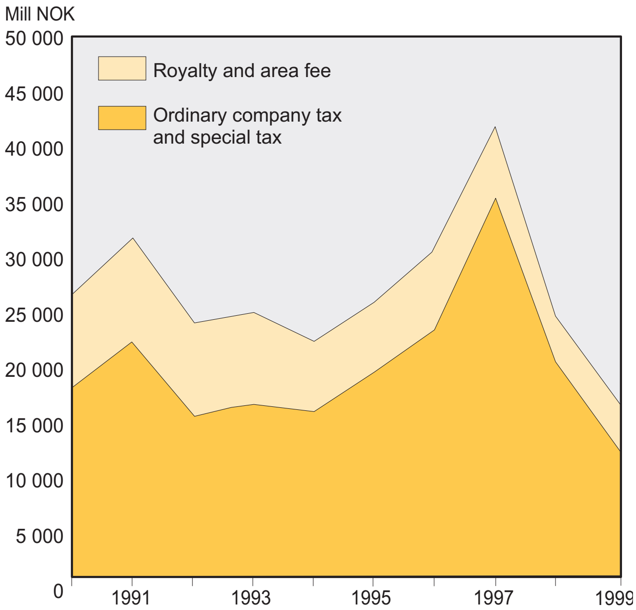
Settlement of royalties paid in cash is on a six-month basis, with a three-month term for payment. The settlement for NGL has been made at contract prices which vary for the individual fields/groups.

There is a reduction in the paid royalty on NGL from 1998 to 1999 of almost 81 per cent. The main reason for the significant reduction has been the discontinuance of the royalty on Ekofisk from and including 7 August 1998.

1.5.7 AREA FEES ON PRODUCTION LICENCES

In 1999, the Norwegian Petroleum Directorate collected NOK 626,198,203 in area fees. The amount is broken down for the various award years as shown in Table 1.5.4.

Figure 1.5.11
Total taxes and royalties 1990 - 1999

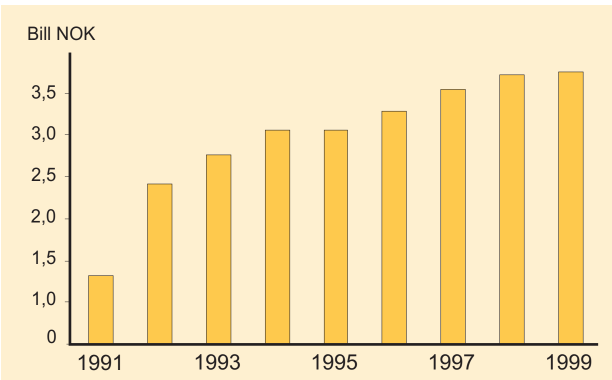


Resource management

Table 1.5.4
Area fees by production licences

Area fees	
Awarded year	NOK
1965	69 073 890
1969	41 586 457
1971	3 900 600
1973	19 810 000
1975	7 350 000
1976	25 536 000
1977	5 897 400
1978	14 658 000
1979	56 112 000
1981	14 136 888
1982	19 993 400
1983	33 390 000
1984	72 646 000
1985	48 608 614
1986	32 889 291
1987	14 180 350
1988	40 728 907
1989	28 172 753
1991	34 510 939
1992	714 886
1993	31 261 325
1995	1 442 000
1998	9 598 504
Total	**626 198 204**

Figure 1.5.12
CO_2 tax paid in 1991-1999 (bill NOK)



The Norwegian Petroleum Directorate has refunded NOK 64,914,382 in area fees in 1999. This represents the deductible portion of the area fee in the royalty settlement for production licenses 006, 018, 018B, 019A, 019B, 033, 037, 050, 053 and 079.

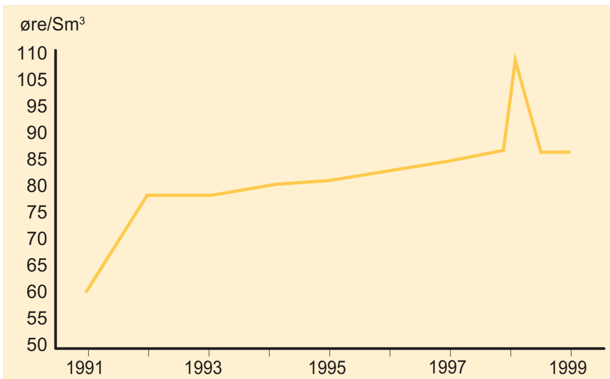
Figure 1.5.10 shows the net area fee receipts for 1990 - 1999. Production royalties and area fees in 1999 accounted

Table 1.5.5
CO_2 tax paid in the first and second half of 1999 (NOK)

Field	1st half	2nd half	Total 1999
Ekofisk area	277 955 719	182 532 277	460 487 996
Frigg area	14 781 355	10 355 044	25 136 399
Gullfaks A+B+C	196 633 990	153 707 289	350 341 279
Yme	22 129 927	20 403 432	42 533 359
Gyda	17 771 745	14 437 370	32 209 115
Heimdal	21 013 730	17 452 010	38 465 740
Hod	85 012	81 662	166 674
Murchison	11 211 673	8 568 093	19 779 766
Oseberg A+B+C	176 292 130	136 558 930	312 851 060
Oseberg Øst	0	9 704 560	9 704 560
Brage	41 730 000	32 012 410	73 742 410
Sleipner	129 790 862	122 837 905	252 628 767
Statfjord A+B+C	278 969 656	220 030 032	498 999 688
Ula	30 037 257	24 874 158	54 911 415
Valhall	61 258 472	49 738 022	110 996 494
Varg	1 868 793	32 455 184	34 323 977
Veslefrikk	39 107 613	22 340 151	61 447 764
Visund	0	32 172 610	32 172 610
Snorre	88 098 448	79 381 059	167 479 507
Draugen	34 414 340	28 694 037	63 108 377
Troll A	1 906 474	456 539	2 363 013
Troll B	71 386 120	55 566 260	126 952 380
Heidrun	78 382 459	63 110 909	141 493 368
Njord A	36 354 320	31 627 040	67 981 360
Norne	69 757 334	60 366 505	130 123 839
Åsgard	0	48 516 831	48 516 831
Ekofisk Bypass	6 630 234	0	6 630 234
Transportation systems			
Norpipe	53 203 176	36 422 628	89 625 804
Statpipe	3 590 125	2 709 865	6 299 990
Total	**1 764 360 964**	**1 497 112 812**	**3 261 473 776**

for 24 per cent of the total taxes and fees paid from the petroleum activities. The proportion of the fees has varied over time. The highest proportion was in 1989 at 53 per cent. Figure 1.5.11 shows total taxes and royalties paid for 1990 - 1999.

Figure 1.5.13
The tax rate for CO_2 - tax (øre/Sm³)



1.5.8 CO_2 TAX

The Act of 21 December 1990 No. 72 relating to tax on emission of CO_2 in the petroleum activities on the continental shelf entered into force on 1 January 1991. The Norwegian Petroleum Directorate has been granted the authority to collect the CO_2 tax and to make administrative decisions necessary to enforce the Act. The tax is calculated on petroleum flared and natural gas or pure CO_2 released to the atmosphere from installations used in connection with production or transportation of petroleum. The CO_2 Act also requires that the companies calculate tax for activities on Norwegian installations for transportation of petroleum which extend beyond the continental shelf. For fields which extend over the median line in relation to another state, the CO_2 tax is only calculated on the Norwegian share.

In the second half of 1998 and the first half of 1999, the CO_2 tax was fixed at NOK 1.07 and 0.89 per Sm^3 gas and NOK 1.07 and 0.89 per liter diesel. The tax is paid on a six-month basis with a three-month term of payment (as of 1 October and 1 April in the following year) by the operator of the individual fields and installations. Table 1.5.5 shows the total tax paid in 1999. The tax is broken down into individual fields and transportation systems. Corrections relating to previous six-month periods are included. A total of NOK 3,261,473,776 was paid in 1999. Figure 1.5.12 shows the yearly receipts of CO_2 tax for 1991-1999 and Figure 1.5.13 shows changes in the tax rate.

1.6 EXPLORATION LICENCES

1.6.1 LICENCES TO EXPLORE FOR PETROLEUM

As of 31 December 1999, a total of 260 exploration licences have been awarded. Such licences are awarded in accordance with the Petroleum Act and have a duration of three years. The following licences were awarded in 1999:

Company	
Aker Geo ASA	253
Mobil Exploration Norway Inc.	254
Petroleum Geo-Services ASA (PGS)	255
GECO A.S	256
Phillips Petroleum Company Norway	257
Norsk Agip A/S	258
Esso Exploration and Production Norway AS	259
Arne Lund	260

1.6.2 LICENCES FOR SCIENTIFIC EXPLORATION

As of 31 December 1999, a total of 329 licences for scientific exploration have been awarded on the Norwegian continental shelf. Such licences are awarded in accordance with the Act relating to scientific research. As illustrated in Table 1.6.1, 13 such licences have been awarded in 1999.

1.7 PRODUCTION LICENCES

The North Sea Round

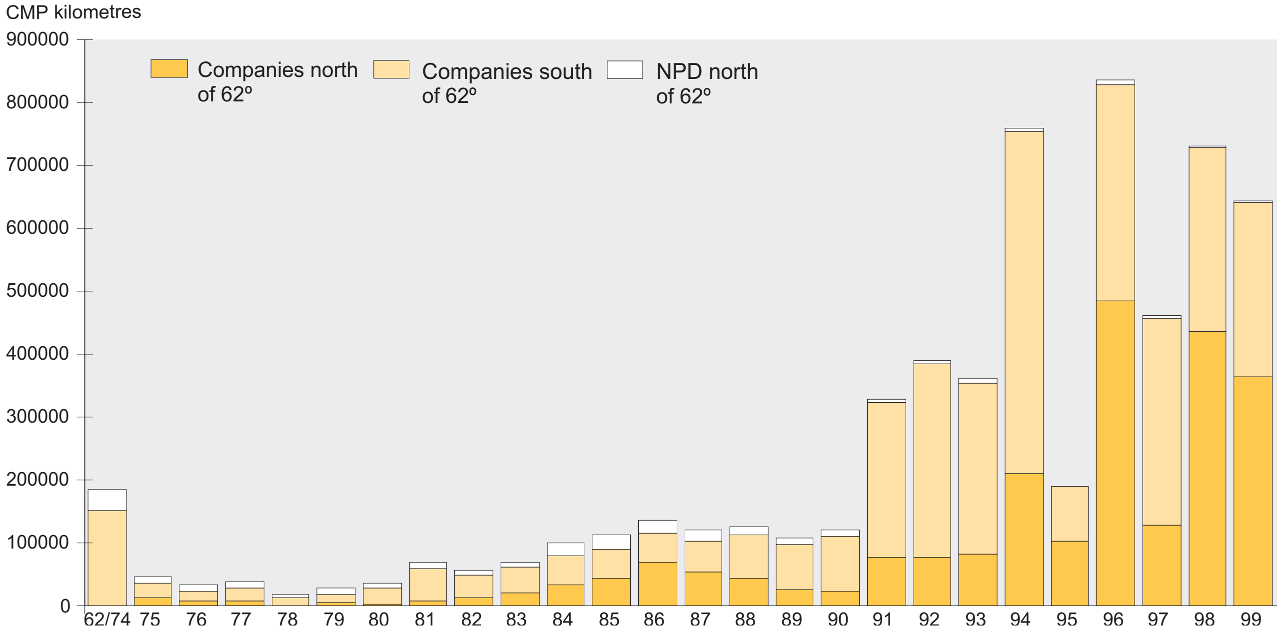
In June 1999, 14 production licences were awarded in the North Sea. Eleven of these were in new areas, while the remaining three were additional acreage to existing discoveries or fields. These were the Production Licences 050 C, 055 B and 249, that were additional acreage to 34/10-23 Gamma (Gullfaks), Brage and 25/4-6 S Vale respectively. The award included a total of 22 blocks or parts of blocks.

Table 1.6.1
Licences for scientific exploration for natural resources

Licence	Name	Subject			Area
		Geophysics	Geology	Other	
317/99	University of Hamburg, Institut für Meereskunde		X	Hydrographic	Skagerrak, North Sea
318/99	University of Odense, Institute of Biology			Biology	Skagerrak
319/99	Danish Institute for Fisheries Research			Hydrographic	Skagerrak
320/99	University of Gothenburg			Hydrographic	Skagerrak
321/99	University of Tromsø, Institute of Geology			Biology Marine geological	Bjørnøyvifta, the Vøring plateau
322/99	Alfred Wegener Institut für Polar- und Meeresforschung	X	X	Biology	Barents Sea/ Greenland Sea
323/99	University of Tromsø, Institute of Geology			Marine geological	Malangen, Balsfjord, Ullsfjord and Lyngen in Troms
324/99	Bundesamt für Seeschiffahrt und Hydrographie		X	Hydrographic	North Sea, Norwegian Sea
325/99	Institut für Meereskunde an der Universität Kiel		X	Biological, Hydrographic, Geochemical	Mid-Norway, Norskerenna
326/99	Institut Francais pour la Recherche			Hydrographic, Climatic	Norwegian Sea/Greenland Sea, Troms
327/99	Netherland's Institute for Sea Research			Biochemical	North Sea, Skagerrak
328/99	Netherland's Institute for Sea Research			Climatic survey, Seabed samples	Drammensfjorden
329/99	University of Tromsø			Marine geological	Andfjorden, Malangsdjupet, Malangsfjorden

Resource management

Fig 1.8.1
Seismic acquisition on the Norwegian continental shelf 1962 - 1999



Awards outside of licence rounds

In 1999, four production licences were awarded outside of licence rounds. One of these, Production Licence 250, was additional acreage to the discovery 6305/8-1 Ormen Lange. The other three were partitions in which part of the acreage in existing production licences was sectioned off and awarded as new production licences. This concerns the Licences 001 B, 027 B and 028 B.

1.8 EXPLORATION ACTIVITIES

1.8.1 GEOPHYSICAL SURVEYS

A total of 640,866 km of seismic data were acquired on the Norwegian shelf in 1999. The number of kilometers refers to cmp-line kilometers.

In the North Sea, a total of 276,777 km of seismic data were acquired, in addition to 362,953 km in the Norwegian Sea and 1,136 km in the Barents Sea.

The Norwegian Petroleum Directorate acquired a total of 3,06 kilometers, while oil companies and seismic contractor companies acquired a total of 637,797 km. Of this total, Norwegian oil companies acquired 94,492 km and foreign oil companies acquired 46,010 km. The contractor companies Aker-Geo, Geco, Fugro-Geoteam, Nopec, PGS Western Geophysical acquired 497,295 km for their own accounts.

Of the total seismic data acquired, 3D seismic accounts for 604,881 km; 276,189 km in the North Sea and 328,692 km in the Norwegian Sea. 3D seismic was not acquired in the Barents Sea in 1999. Figure 1.8.1 provides an overview of the development with regard to the number of cmp-line kilometers acquired.

1.9 EXPLORATION ACTIVITY

1.9.1 EXPLORATION DRILLING

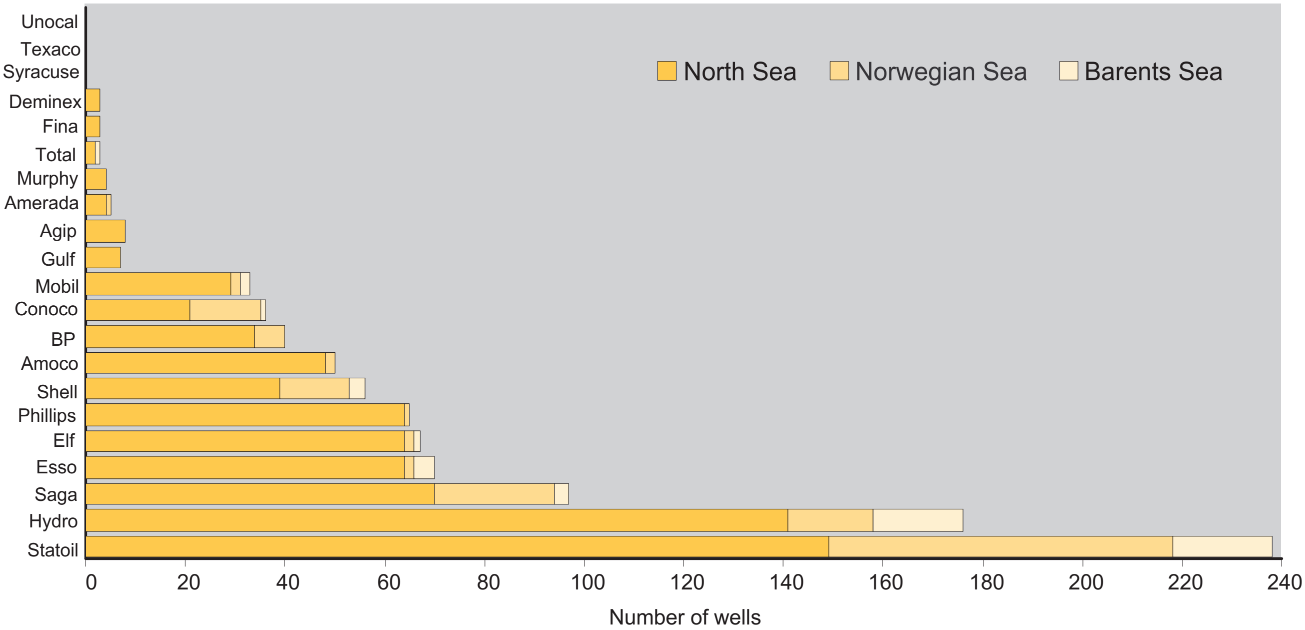
At the turn of 1998/1999, drilling of four exploration wells was in progress, one of which was a re-entry.

Twenty-two exploration wells were spudded in 1999, of which 15 were wildcats and seven were appraisal wells. Drilling activities in 1999 comprised six wildcat and five appraisal wells in the North Sea and nine wildcat wells and two appraisal wells in the Norwegian Sea. In addition, two temporarily abandoned exploration wells were re-entered for further work; both in the North Sea. At the turn of 1998/1999, no exploration wells were being drilled. As of 31 December 1999, a total of 964 exploration wells had been spudded on the Norwegian continental shelf. These are divided between 688 wildcat wells and 276 appraisal wells. Regional distribution of exploration wells per operating company is shown in Figure 1.9.1.

In 1999, 27 exploration wells were completed or temporarily abandoned on the Norwegian shelf. Two of these were re-entries for further operations. The exploration wells are divided between 18 wildcat wells and 9 appraisal wells. The geographical distribution of the wells is as follows: Eight wildcat and six appraisal wells in the North Sea and ten wildcat and three appraisal wells in the Norwegian Sea. The operators for the wells completed or temporarily abandoned in 1999 were as follows: Statoil nine, Saga seven, Esso three, BP Amoco and Shell two each and Phillips, Amoco and Conoco one each.

A wildcat well is a well which is drilled in order to investigate whether petroleum may be found in a new, clearly defined geological unit, delimited by rock formations with structural or stratigraphic limits. An appraisal well is a well

Figure 1.9.1
Regional spread of exploration wells per operator



drilled in order to determine the extent and size of a petroleum deposit which has already been proven by a wildcat well. All exploration wells have one of these classifications when they are spudded. If it should later prove that a well does not meet the criteria for the classification it was originally given, it is reclassified. Seventy-six exploration wells have been reclassified on the Norwegian continental shelf, 72 of these from wildcat to appraisal wells and four from appraisal to wildcat wells.

As of 31 December 1999, 964 exploration wells were completed or temporarily abandoned on the Norwegian shelf. After reclassification, these comprise 620 wildcat and 344 appraisal wells (Figure 1.9.2).

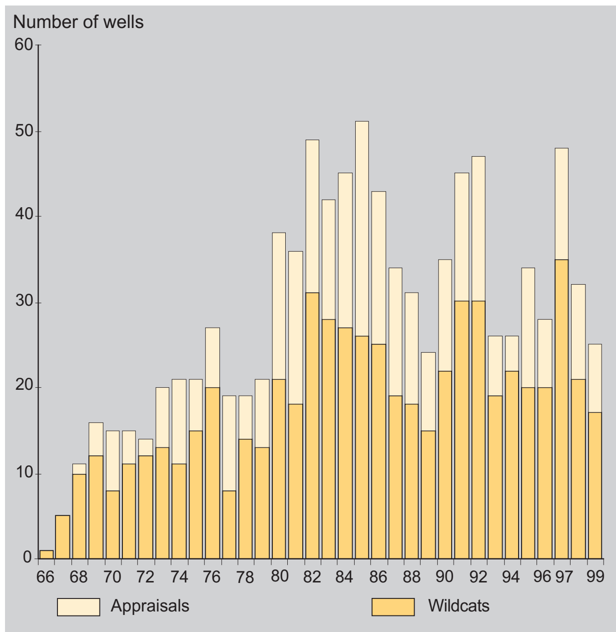
As of year-end, a total of 49 exploration wells have been temporarily abandoned on the Norwegian shelf. The temporarily abandoned exploration wells with equipment remaining on the seabed are:

1/03-09 S	25/08-11	34/08-04 A
2/01-09 A	25/11-16	34/10-34
2/01-11	25/11-21 A	34/10-37 A
2/04-15 S	30/02-01	34/11-02 S
2/04-17	30/03-04	35/09-04 S
2/07-23 S	30/08-01 SR	6305/05-01
2/07-25 S	30/09-07	6406/02-02
2/07-31	30/09-08 R	6406/02-06
2/10-02	30/09-09	6407/07-02 R
2/12-02 S	30/09-10	6407/07-04
7/12-08	30/09-12 A	6504/11-05 S
7/12-09	30/09-13 S	6506/12-08
15/12-10 S	31/02-16 SR	6506/12-11 SR
25/02-13	31/02-18 A	6507/05-01
25/04-06 S	31/05-04 AR	6507/08-04
25/05-04	31/05-05	
25/08-06	31/04-07	

1.9.2 EXPLORATION TARGETS

Exploration activity in 1999 has largely been targeted on Jurassic sandstone prospects. Of the 28 exploration wells spudded in 1999, 24 had Jurassic as the main prospect, three had the Tertiary, and one had the Cretaceous as the main prospect.

Figure 1.9.2
Exploration wells completed per year after reclassification



1.9.3 NEW DISCOVERIES IN 1999

Five discoveries have been made, of which two have been confirmed through formation testing. Two discoveries have been made in the North Sea and three in the Norwegian Sea (Table 1.9.2).

1.9.4 DETAILED DESCRIPTION OF DRILLING IN 1999

Southern part of the North Sea

Three wildcat wells, see Figure 1.9.3, were completed in the southern part of the North Sea in 1999 (Table 1.9.3). Two discoveries were made in the area.

Table 1.9.2
New discoveries in 1999

Exploration well	Operator	Hydrocarbon type	Reservoir level	Formation tested	Flow rate (per day)	Choke opening	Size of discovery (recoverable resources) Oil/condensate (Million Sm^3)	Size of discovery (recoverable resources) Gas (Billion Sm^3)
9/2-9 S	Statoil	oil	Early and Middle Jurassic	no			<1	
2/7-31	Phillips	oil/gas	Early and Middle Jurassic/ Permian	yes	283 Sm^3 oil 120000 Sm^3 gas	6.3 mm	2-6	2-5
6507/3-3	Statoil	gas	Early and Middle Jurassic	no				15-20
6407/9-9	Shell	oil	Early Jurassic	no			<1	
6407/9-9	Shell	oil/gas	Middle Jurassic	no			< 1	1.6
6406/2-7	Saga	gas/cond.	Jurassic	yes	496 000 Sm^3 gas/d 678 Sm^3 cond./d	12.7 mm	40 -50 condensate	40 -55

Well 2/7-31, drilled on the Ebba structure west of the Eldfisk field, proved oil and gas. The well was formation tested and a stable production rate was metered to 283 Sm^3 oil and 120,000 Sm^3 gas per day through a 6.35-mm choke opening.

Well 9/2-9, drilled on a segment of the Beta structure west of the Yme field, proved oil. The well was not tested and has now been reclassified as a production well.

Mid-North Sea

Six exploration wells were completed in the Mid-North Sea area in 1999 (Figures 1.9.4 and 1.9.5). Three were wildcat wells and three were appraisal wells. None of the three wildcat wells proved recoverable hydrocarbons. The three appraisal wells were drilled in the Balder area. Based on 25/8-12 A and S and 25/11-23, it has been decided to develop several new structures around Balder. This development has been assigned the name Ringhorne. Resource growth due to these wells is in the vicinity of 10 – 12 million Sm^{3}o.e.

Tampen Area

Four exploration wells, all appraisal wells, see Figure 1.9.6, were completed in the area in 1999 (Table 1.9.5). Appraisal well 34/7-29 S/SR in the vicinity of the Vigdis field was

Figure 1.9.3
Exploration wells drilled in the Southern North Sea

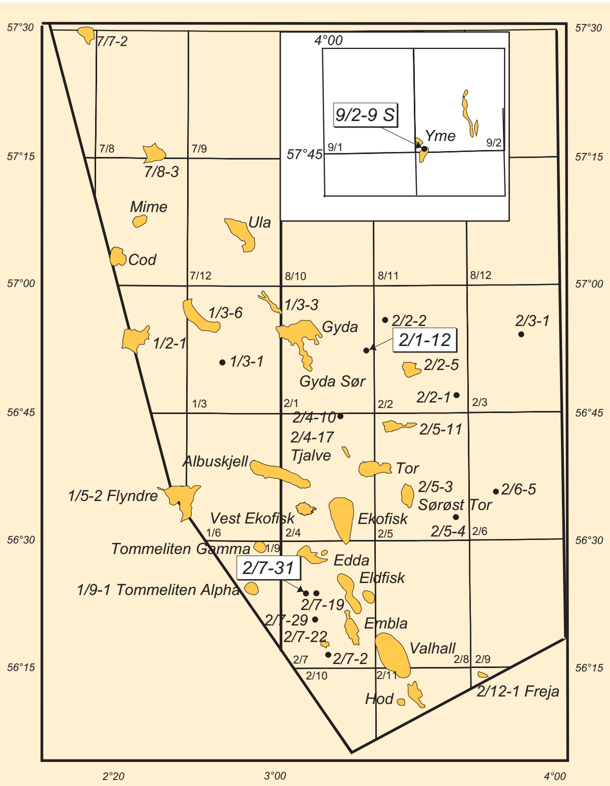


Figure 1.9.4
Exploration wells drilled in the Sleipner and Balder area

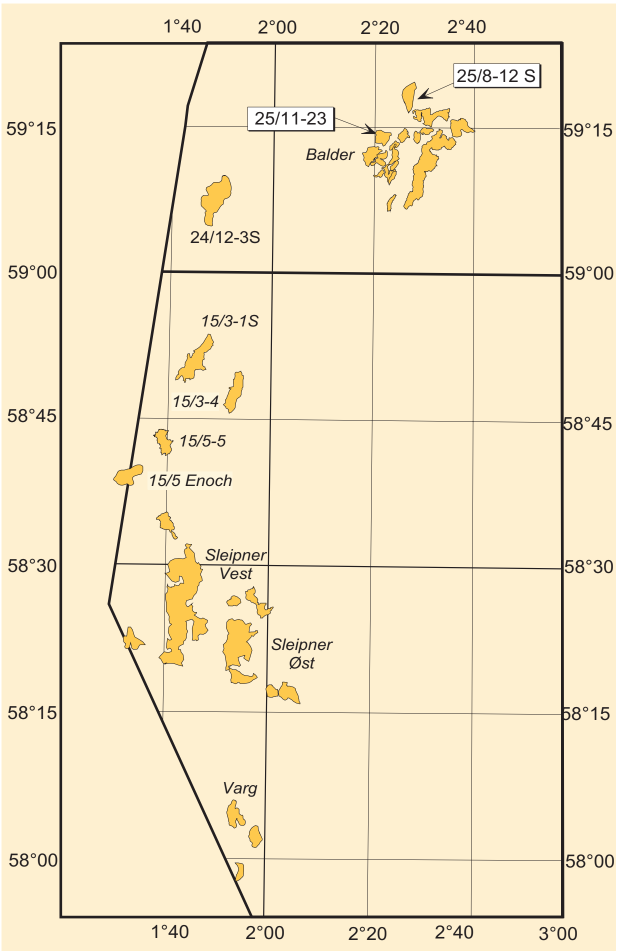


Table 1.9.3
Exploration wells drilled in the southern North Sea

Exploration well	Well classification	Production licence (PL)	Operator	Total vertical depth (MSL)	Total depth (age)	Status (31 Dec. 1999)
2/1-12	wildcat	019C	BP Amoco	3550	Jurassic	dry
2/7-31	wildcat	018	Phillips	4968	Permian	oil/gas
9/2-9 S	wildcat	114	Statoil	4367	Jurassic	oil

Table 1.9.4
Exploration wells drilled in Mid-North Sea in 1999

Exploration well	Well classification	Production licence (PL)	Operator	Total vertical depth (MSL)	Total depth (age)	Status (31 Dec. 1999)
25/6-3	wildcat	245	Statoil	2350	Cretaceous	dry
25/8-12 S	appraisal	001	Esso	2073	Triassic	oil
25/8-12 A	appraisal	001	Esso	2133	Triassic	oil
25/11-23	appraisal	001	Esso	1911	Jurassic	oil
30/6-25 S	wildcat	053	Hydro	2935	Early Jurassic	dry
35/8-4	wildcat	195	BP Amoco	3701	Upper Jurassic	dry
35/10-3	wildcat	173	Statoil	2223	Cretaceous	dry

Table 1.9.5
Exploration wells drilled in the Tampen area in 1999

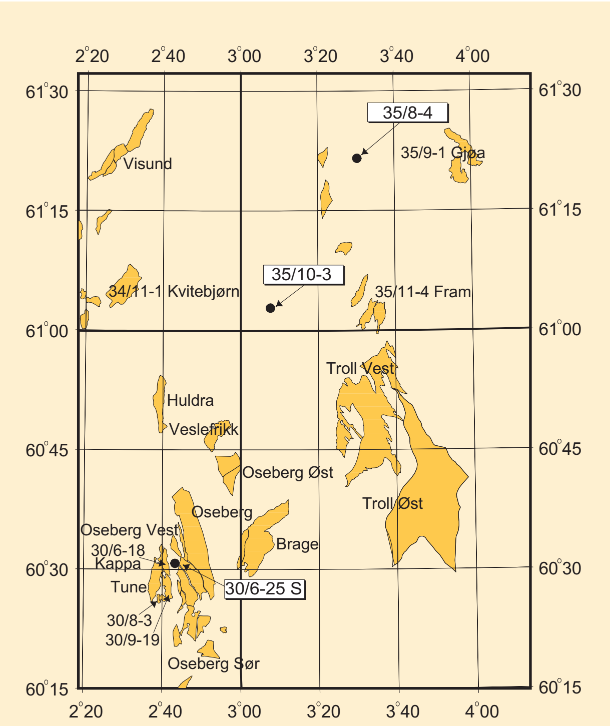
Exploration well	Well classification	Production licence (PL)	Operator	Total vertical depth (MSL)	Total depth (age)	Status (31 Dec. 1999)
34/7-29 SR	appraisal	089	Saga	2823	Middle Jurassic	oil
34/11-4	appraisal	193	Statoil	4414	Early Jurassic	gas/cond.
34/10-42	appraisal	050	Statoil	4352	Early Jurassic	dry
34/7-30 SR	appraisal	089	Saga	2245	Late Jurassic	dry

Table 1.9.6
Exploration wells drilled in the Norwegian Sea

Exploration well	Well classification	Production licence (PL)	Operator	Total vertical depth (MSL)	Total depth (age)	Status (31 Dec. 1999)
6406/2-7	wildcat	199	Saga	4953	Early Jurassic	gas/cond.
6406/2-4 SR	wildcat	199	Saga	4969	Early Jurassic	gas/cond.
6407/6-5	appraisal	092	Statoil	2734	Early Jurassic	oil/gas
6407/9-9	wildcat	093	Shell	1920	Middle Jurassic	oil/gas
6407/12-1	wildcat	176	Shell	1782	Middle Jurassic	oil
6507/3-3	wildcat	159	Statoil	3821	Early/ Middle Jurassic	gas
6507/3-3 A	wildcat	159	Statoil	3717	Early/ Middle Jurassic	gas
6507/3-3 B	wildcat	159	Statoil	3841	Early/ Middle Jurassic	gas
6507/5-2	appraisal	212	BP Amoco	3877	Early Jurassic	gas
6507/7-12	wildcat	095	Conoco	3976	Late Jurassic	dry
6508/1-1S	wildcat	213	Saga	2724	Early Jurassic	dry
6508/1-1 A	wildcat	213	Saga	2539	Late Jurassic	dry
6704/12-1	wildcat	215	Saga	4078	Late Cretaceous	dry

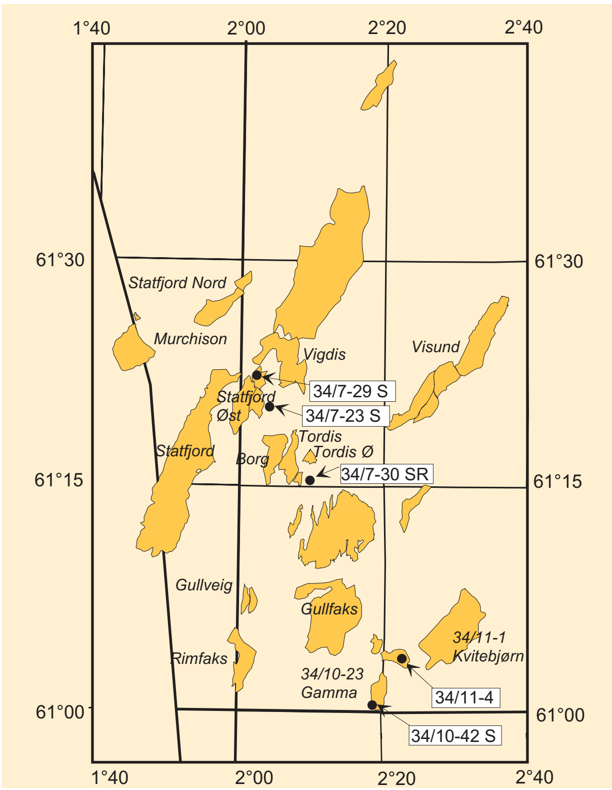
Resource management

Figure 1.9.5
Exploration wells drilled in the Oseberg and Troll area, Fram and Gjøa area



drilled in 1998, but was tested in 1999. The well flowed 900 Sm^3 oil per day through a 17.5 mm choke opening. It is a small discovery, but it represents interesting additional resources in the Vigdis area. Appraisal well 34/11-4 on the Mats structure between Gullfaks Gamma and Kvitebjørn

Figure 1.9.6
Exploration wells drilled in the Tampen area



proved gas condensate at a great depth in the Brent group and confirmed that this geologically complex area contains significant gas resources. However, appraisal well 34/10-42 S far south on the Gamma structure was dry. The entire Gamma - Kvitebjørn area is now being reappraised.

The Norwegian Sea

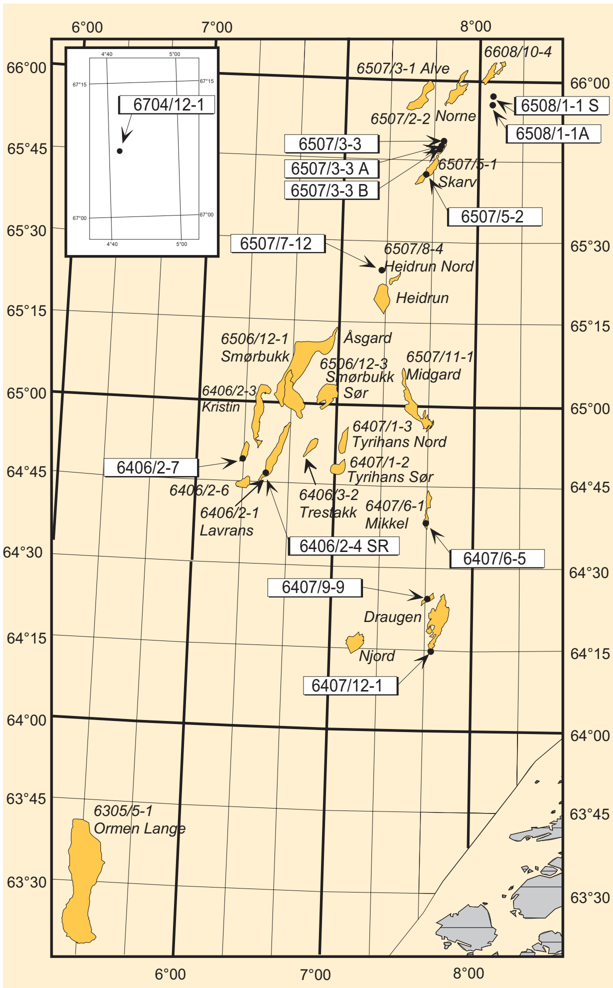
Thirteen exploration wells, see Figure 1.9.7, were completed in this area in 1999, of which 11 were wildcat wells and two were appraisal wells (Table 1.9.6).

Exploration for oil and gas in deep water continued in 1999. Saga Petroleum drilled a dry well on the Gjallar ridge at a water depth of 1352 meters, so far the greatest depth drilled on the Norwegian continental shelf. Based on this, the result of the first round of drilling in deep water was the two gas discoveries 6707/10-1Nyk and 6305/8-1Ormen Lange with total gas resources in the vicinity of 360 billion Sm^3.

There were three new discoveries of hydrocarbons in the area in 1999.

Statoil, as the operator for well 6507/3-3, made a gas discovery named 6507/3-3 Idun on the Dønna terrace. Appraisal wells 6507/3-3 A and B confirmed the extent of the discovery. The Idun discovery is located north of the oil

Figure 1.9.7
Exploration wells drilled in the Norwegian Sea



and gas discovery Skarv, which was proven by BP Amoco in 1998. Appraisal well 6507/5-2 on the Skarv discovery confirmed gas. Development plans are being prepared for both discoveries.

Saga Petroleum, as the operator for well 6406/2-7, made a new gas/condensate discovery southwest of the Kristin discovery on the Halten terrace. Even though the resource estimate is uncertain, the discovery may make a significant contribution in the event of a development of the discoveries to the south on Haltenbanken. In addition, Shell has made a small gas and oil discovery (6407/9-9) in a structure north-west of the Draugen field, as well as drilled appraisal well 6407/12-1 to the south on the Draugen field.

1.10 DEVELOPMENT AND OPERATIONS

1.10.1 THE NORTH SEA

FIELDS IN PRODUCTION AND FIELDS APPROVED FOR DEVELOPMENT

HOD

Production licence:	033	Block:	2/11
Operator: BP Amoco Norge AS			
Licensees:			
Amerada Hess Norge AS			25.00000 %
BP Amoco Norge AS			25.00000 %
Elf Petroleum Norge AS			25.00000 %
Enterprise Oil Norwegian AS			25.00000 %
Discovery well:	2/11-2	Year:	1974
Development approved:	1988	Prod.start:	1990
	1994		
Recoverable reserves:		8.2	mill. Sm³ oil
		1.5	bill. Sm³ gas
		0.2	mill. tonnes NGL
		0.0	mill. Sm³ cond.
Total investments (firm 1999-NOK):		1.6 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		113 mill.	

Production

The Hod field, see Figure 1.10.1, is the southernmost chalk field in the Norwegian part of the North Sea, and produces from reservoir zones in the Ekofisk, Tor and Hod formations. The field is divided into the three structures Hod Vest, Hod Øst and Hod Sadel. Both the western and the eastern structure were proven in 1974. Oil was proven in the Hod Sadel area in 1994.

The field is produced with the aid of depressurization. A total of eight wells have been drilled. Four of these wells were in production at the end of 1998. A study has been initiated to evaluate future plans for Hod and a new reservoir model has been prepared.

Development

The development features an unmanned production installation (Figure 1.10.2). The installation is remote-controlled from the Valhall field, 13 kilometers to the north. Oil and gas are separated by means of a separation unit and

Figure 1.10.1
Fields and discoveries in the Ekofisk area

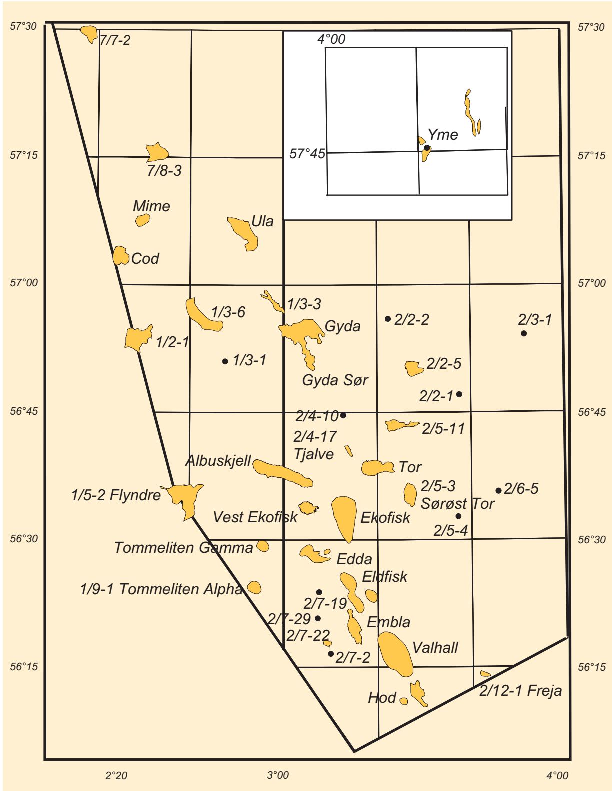
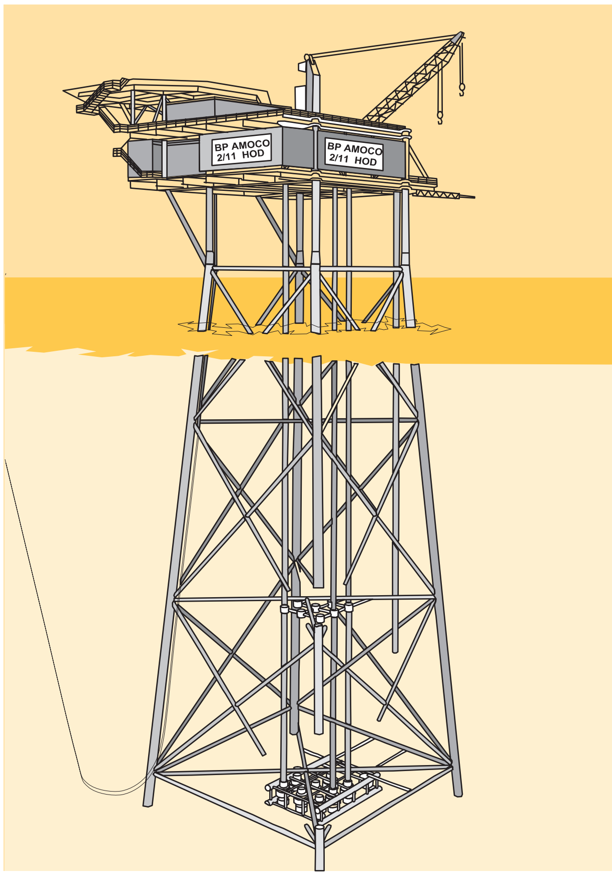


Figure 1.10.2
Installation on Hod



then metered before being transported via pipeline to Valhall for further processing. Oil and gas are transported in a common pipeline to Valhall and then in the existing transportation systems to Teesside and Emden.

VALHALL

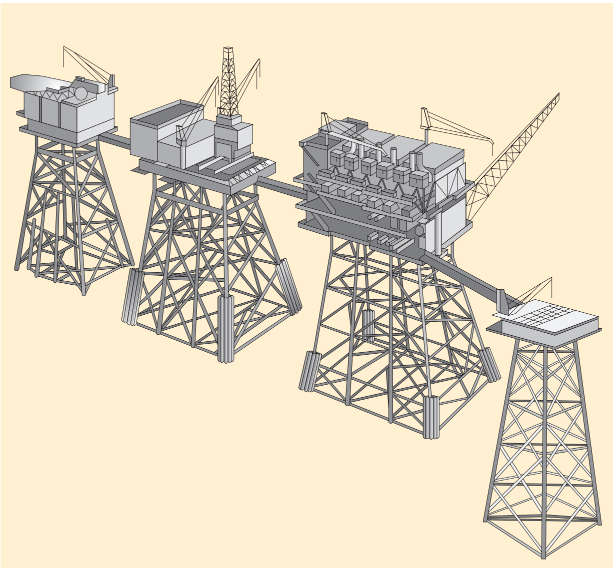
Business area:	Valhall Unit			
Production licence:	006, 033	**Block:**	2/11, 2/8	
Operator: BP Amoco Norge AS				
Licensees:				
Amerada Hess Norge AS			28.09376 %	
BP Amoco Norge AS			28.09377 %	
Elf Petroleum Norge AS			15.71871 %	
Enterprise Oil Norwegian AS			28.09376 %	
Discovery well:	2/8-6	Year:	1975	
Development approved:	1977	Prod.start:	1982	
	1995			
Recoverable reserves:		132.3	mill. Sm^3 oil	
		31.2	bill. Sm^3 gas	
		4.5	mill. tonnes NGL	
		0.0	mill. Sm^3 cond.	
Total investments (firm 1999-NOK):		26.0 bill		
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		787 mill.		

Production

The Valhall field, see Figure 1.10.1, produces from limestone in the Ekofisk, Tor and Hod formations from the Early Paleocene to the Upper Cretaceous Age. The production strategy on Valhall is based on depressurization with a high degree of compacting drive. Compacting of the reservoir rocks has led to subsidence of the seabed estimated at about 3.9 meters at the end of 1999. At the end of 1999, 40 production wells were producing on the field.

In order to increase the recovery rate of the oil, the operator is considering the possibility of starting water injection on the field. Water injection can be commenced from a new wellhead installation with 15 injectors.

Figure 1.10.3
Installations on Valhall



Development

Valhall was originally developed with three installations, one for living quarters, one drilling and one production installation. In May 1996, a new riser installation was installed with room for 19 wells. The four installations are connected to each other by gangways. Figure 1.10.3 shows these installations.

Oil is separated from gas on Valhall by means of two separation units. The heavier gas fractions, NGL, are separated on Valhall using a fractionating tower and are then mainly transported in the oil stream.

Oil and NGL are transported by pipeline to Ekofisk for further transportation to Teesside. Gas is transported in a new pipeline to Norpipe for further transportation to Emden. The oil production capacity is 27,000 Sm^3 oil/day and the gas treatment capacity is 10.7 million Sm^3 gas/day. Oil and gas are fiscally metered on Valhall. Oil is metered on the production installation and gas on the riser installation. The metering systems are part of the Ekofisk hydrocarbon distribution system.

EKOFISK AREA

Figure 1.10.1 shows the fields in the Ekofisk area. As of 1 January 1999, the ownership distribution in Production License 018 was changed. SDFI received a five-per cent interest and the licensees' interests were reduced accordingly.

Production from Ekofisk started in 1971, and during the first years the field produced to loading ships from four wells until 1973 when the concrete tank with process facilities was in place. The Cod, Tor and Vest Ekofisk fields were developed and tied in to the Ekofisk Center from 1976-1978. At the same time, an oil pipeline was laid to Teesside and a gas pipeline to Emden. In 1979, the Albuskjell, Edda and Eldfisk fields were tied in to the Ekofisk Center. Production from Embla started in May 1993. The Ekofisk area comprises a total of 26 permanent installations.

Due to the subsidence of the seabed and an expectation of production from the field for a long time to come, development of Ekofisk II was decided in 1994. The development has included a drilling and wellhead installation for Ekofisk, 2/4-X, and a joint process and export installation, 2/4-J. Both installations are tied to the old field center by gangways.

Ekofisk II started producing in August 1998. Ekofisk, Eldfisk, Tor and Embla are connected to the new field center, while the installations on Albuskjell, Cod, Edda and Vest Ekofisk were shut down. At the same time, the installations at the northern part of the Ekofisk Center were shut down A decommissioning plan for Ekofisk I was submitted to the authorities in October 1999. The decommissioning plan for riser installation 2/4-S, owned by Statpipe, was considered by the Norwegian Petroleum Directorate in 1999. Figure 1.10.4 shows the installations in the Ekofisk area at the end of 1999.

EKOFISK

Production licence:	018	**Block:**	2/4
Operator: Phillips Petroleum Company Norway			
Licensees:			
Den norske stats oljeselskap a.s (SDFI 5,000 %)			5.95000 %
Elf Petroleum Norge AS			8.02600 %
Fina Production Licenses AS			28.50000 %
Norsk Agip AS			12.38800 %
Norsk Hydro Produksjon AS			6.36500 %
Phillips Petroleum Company Norway			35.11200 %
Saga Petroleum ASA			0.28900 %
Total Norge AS			3.37000 %
Discovery well:	2/4-2	ear:	1969
Development approved:	1972	rod.start:	1971
	1994		
Recoverable reserves:		417.1	mill. Sm^3 oil
		142.2	bill. Sm^3 gas
		13.3	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		86.1 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		2.2 mill.	

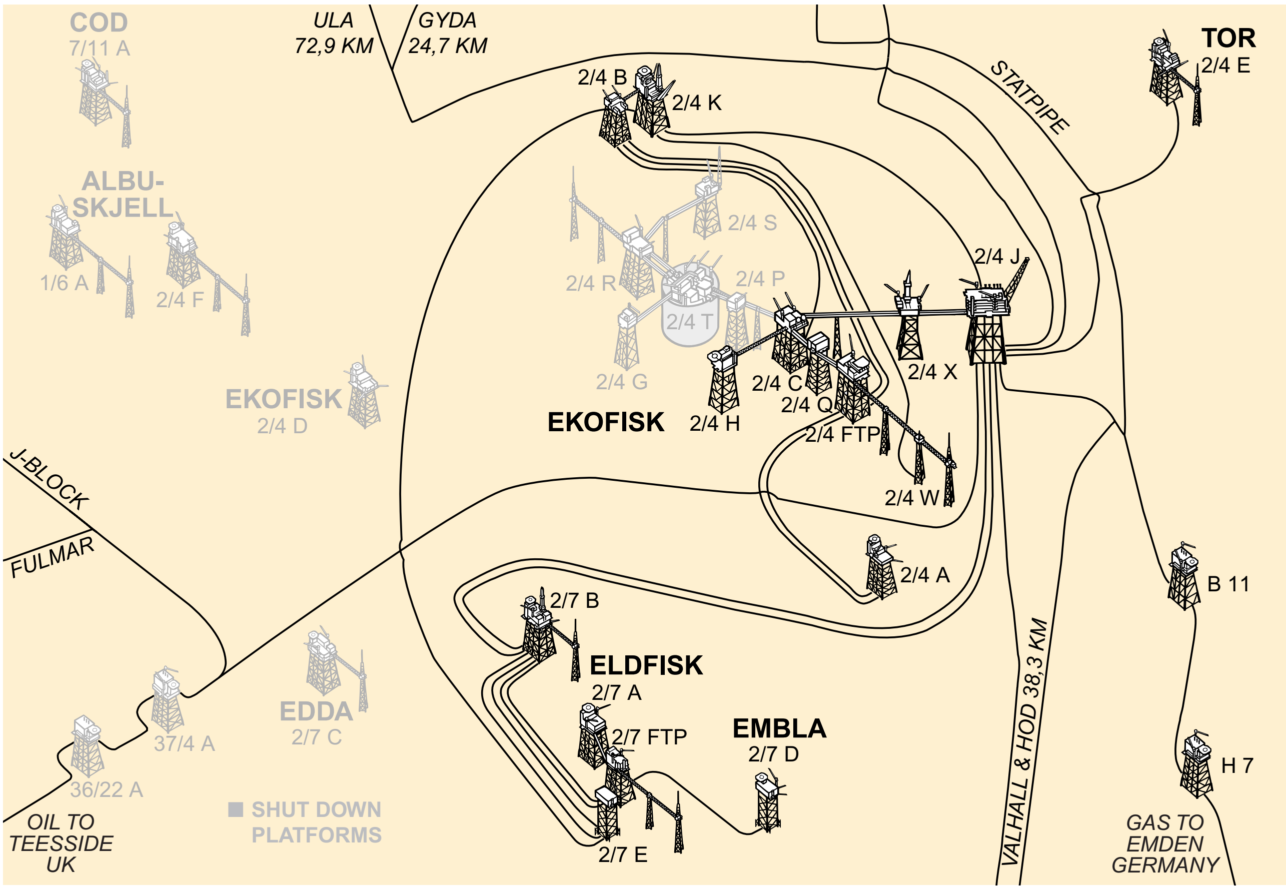
Production

The reservoir on Ekofisk lies at a depth of about 3000 meters and consists of jointed chalk rocks from the Tor and Ekofisk formations. Ekofisk is the largest field in the area, and the second largest oil field on the Norwegian continental shelf in terms of recoverable reserves. About 80 production wells drain the field. Currently, somewhat less than 60 wells are in use due to the facilities' capacity constraints.

Ekofisk was originally developed with depressurization as the drive mechanism. Subsequently, limited gas injection and comprehensive water injection have contributed to a considerable increase in the rate of recovery of oil, from the original approximately 18 per cent to the current 41 per cent. Large-scale water injection began in 1987, and in the subsequent years the area for water injection has been expanded in several stages. Every day about 110,000 m^3 of water is injected into the reservoir from 38 wells. A total of 368 million m^3 of water was injected up to December 1999. Experience has shown that the water's displacement of the oil is more effective than expected, and the reserves estimate has been adjusted accordingly. In addition to water injection, the compacting of the soft chalk rocks also provides an extra drive for drainage of the field. This is reinforced by the fact that the injected water contributes to the weakening of the chalk. Ekofisk is expected to produce until 2028.

Measurements of the subsidence of the seabed at Ekofisk show that the rate of subsidence has decreased in the past year and is now at the lowest level ever measured. The total subsidence as of November 1999 was 7.95 meters at Ekofisk H. The subsidence rate in 1999 was approximately 14 cm, compared with slightly less than 40 cm in the previous years. It is assumed that the reduction is caused by

Figure 1.10.4
Installations in the Ekofisk area



the build-up of pressure taking place in the reservoir as more liquid is injected than is produced. This reduction in subsidence means that the two wellhead installations 2/4-A and 2/4-B can be used longer than previously anticipated and that the construction of a new hotel installation can be delayed.

Development

Figure 1.10.4 shows the installations in the Ekofisk area. 15 of these are located on the Ekofisk field. The Ekofisk Center now consists of 12 installations connected by gangways, but only four of these are included in the new field center for Ekofisk II: the living quarters installation 2/4-H, the production installation 2/4-C, the new drilling and production installation 2/4-X and the new process installation 2/4-J. As for the other installations on the center, 2/4-FTP and 2/4-W are still in operation as a riser installation for the production from 2/4-A and -B and a wellhead installation for water injection. In addition, 2/4-K to the north on the field is used as the main installation for water treatment and injection in Ekofisk. The lifetime for production installations 2/4-A and 2/4-B can be extended due to reduced subsidence on the field. This frees up drilling capacity on 2/4-X for exploring for oil on the flank areas on the field. Together with the findings of the new 3D seismic obtained in 1999, this could increase the reserves on Ekofisk. In the autumn of 1999, a contracted installation for production of injection water was released from the contract. In the future, the additional water volumes that are required will come from Eldfisk.

Oil and gas are routed to the export pipelines via the process facility at 2/4-J on Ekofisk. After Ekofisk II was put into operation in August 1998, technical problems with the process facility have led to reduced capacity and reduced export from 2/4-J. However, towards the end of 1999 the facility has operated well and production has been high.

The gas from the Ekofisk area is transported via pipeline to Emden, while the oil, which contains the NGL fractions, is sent by pipeline to Teesside.

Total investments (firm 1999-NOK):	35.5 bill
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:	612 mill.

Production

Eldfisk is the second largest field in the Ekofisk area. The Eldfisk reservoir lies at a depth of about 2800 meters and consists of jointed chalk rocks belonging to the Tor, Ekofisk and Hod formations. The field has a total of 47 wells, but produces only from 25 wells from three separate structures; Alfa, Bravo and Øst Eldfisk. Since production started in 1979, Eldfisk has employed depressurization as the drive mechanism. A plan for development and operation of Eldfisk with full field water injection in the Alfa and Bravo structures and limited gas injection in the Alfa structure was approved by the authorities in December 1997. The water injection will start in February 2000 and the gas injection in March 2000. Drilling of new wells started in 1999 and will continue in the years ahead.

Development

Eldfisk was originally developed with three installations. Eldfisk B is a combined drilling, wellhead and process installation, while Eldfisk A and FTP are a wellhead and process installation connected by a gangway. Eldfisk was tied in to the new Ekofisk Center in August 1998 and is expected to produce until around 2017. Oil and gas are transported in two pipelines to the Ekofisk Center for further transportation to Teesside and Emden. Modifications have been made on Eldfisk and Ekofisk so that the oil from Eldfisk can go directly to the export pumps on 2/4-J. A new installation for water injection, 2/7-E, was installed on the field in 1999 and is connected to FTP by a gangway. The installation will also supply the Ekofisk field with some injection water through a new water pipeline from Eldfisk to Ekofisk 2/4-K. Simultaneously with the development for water injection, one of the existing installations was modernized, inter alia through the replacement of old power generators.

ELDFISK

Production licence:	018	**Block:**	2/7
Operator:	Phillips Petroleum Company Norway		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 5,000 %)			5.95000 %
Elf Petroleum Norge AS			8.02600 %
Fina Production Licenses AS			28.50000 %
Norsk Agip AS			12.38800 %
Norsk Hydro Produksjon AS			6.36500 %
Phillips Petroleum Company Norway			35.11200 %
Saga Petroleum ASA			0.28900 %
Total Norge AS			3.37000 %
Discovery well:	2/7-1	ear:	1970
Development approved:	1975	rod.start:	1979
	1994		
	1997		
Recoverable reserves:		109.1	mill. Sm^3 oil
		50.7	bill. Sm^3 gas
		4.2	mill. tonnes NGL
		0.0	mill. Sm^3 cond.

EMBLA

Production licence:	018	**Block:**	2/7
Operator:	Phillips Petroleum Company Norway		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 5,000 %)			5.95000 %
Elf Petroleum Norge AS			8.02600 %
Fina Production Licenses AS			28.50000 %
Norsk Agip AS			12.38800 %
Norsk Hydro Produksjon AS			6.36500 %
Phillips Petroleum Company Norway			35.11200 %
Saga Petroleum ASA			0.28900 %
Total Norge AS			3.37000 %
Discovery well:	2/7-20	Year:	1988
Development approved:	1990	Prod.start:	1993
	1995		
Recoverable reserves:		14.5	mill. Sm^3 oil
		7.2	bill. Sm^3 gas
		0.7	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		3.3 bill.	

Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:	36 mill.

Production
Embla is a segmented sandstone reservoir of the Devonian and Jurassic Ages which lies at a depth of more than 4000 meters. The field produces from two separate sand layers, in addition to a dolomite layer discovered in 1999, with depressurization as the drive mechanism. The field has a total of six wells of which two were drilled in 1999. Complex geology and poor seismic data have made surveys of the field difficult. New surveys and well results indicate that it may be possible to increase the resources from the field and there are plans to drill more wells.

Development
Embla started producing in 1993 with an unmanned wellhead installation which is remote-controlled from Eldfisk. Oil and gas are transported to Eldfisk and on to the Ekofisk Center for export. Embla is expected to produce until around 2017.

TOR

Business area:	Tor Unit			
Production licence:	006, 018	**Block:**	2/4, 2/5	
Operator:	Phillips Petroleum Company Norway			
Licensees:				
Amerada Hess Norge AS			8.73766 %	
Den norske stats oljeselskap a.s (SDFI 3,687 %)			4.51692 %	
Elf Petroleum Norge AS			11.63419 %	
Fina Production Licenses AS			24.88473 %	
Norsk Agip AS			10.81656 %	
Norsk Hydro Produksjon AS			5.55758 %	
Phillips Petroleum Company Norway			30.65799 %	
Saga Petroleum ASA			0.25216 %	
Total Norge AS			2.94221 %	
Discovery well:	2/5-1	Year:	1970	
Development approved:	1973	Prod.start:	1978	
Recoverable reserves:		27.2	mill. Sm^3 oil	
		11.5	bill. Sm^3 gas	
		1.2	mill. tonnes NGL	
		0.0	mill. Sm^3 cond.	
Total investments (firm 1999-NOK):		7.2 bill.		
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		150 mill.		

Production
The main reservoir on Tor lies at a depth of about 3200 meters and consists of jointed chalk rocks belonging to the Tor formation. The Ekofisk formation also contains oil, but has poorer production properties. In 1992, limited water injection was implemented on Tor, but due to problems with the production wells, no water has been injected in 1999. The plan is to start up water injection again in February 2000 and it is expected to last the rest of the field life. Due to low oil prices in early 1999, the field was considered for shutdown. Work is in progress for improving the field's profitability, both through increased production and lower cost.

Development
The Tor field was developed with a combined wellhead and process installation with transportation through pipelines to the Ekofisk Center for export. Tor was tied in to the new Ekofisk Center in August 1998 and is expected to produce until around 2019.

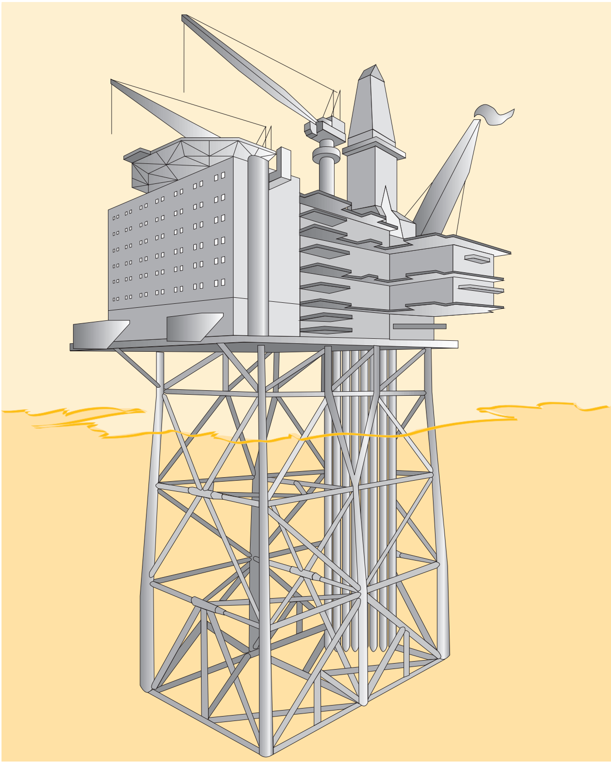
GYDA

Production licence:	019 B	**Block:**	2/1	
Operator:	BP Amoco Norge AS			
Licensees:				
AS Pelican				4.00000 %
BP Amoco Norge AS				56.00000 %
Den norske stats oljeselskap a.s (SDFI 30,000 %)				30.00000 %
Norske AEDC A/S				5.00000 %
Norske MOECO A/S				5.00000 %
Discovery well:	2/1-3	Year:	1980	
Development approved:	1987	Prod.start:	1990	
Recoverable reserves:		30.7	mill. Sm^3 oil	
		3.8	bill. Sm^3 gas	
		1.5	mill. tonnes NGL	
		0.0	mill. Sm^3 cond.	
Total investments (firm 1999-NOK):		11.8 bill.		
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		342 mill[1]		

[1] Includes Gyda Sør

Production
The reservoir is made up of Upper Jurassic sandstone. Gyda is produced using water injection as the drive mechanism, see Figure 1.10.1. At the end of 1999, there were a total of 13 production wells and 10 water injection wells on the

Figure 1.10.5
Installation on Gyda



field. Water production is increasing and measures to reduce water production are being evaluated continuously.

Development

The development solution for the field consists of a combined drilling, living quarters and processing installation with a steel jacket, see Figure 1.10.5. Production capacity is currently 14,300 Sm^3 oil per day and 1.8 million Sm^3 gas per day. Water injection capacity is 24,500 m^3 per day.

The oil is transported to Ekofisk via the oil pipeline from Ula, and then on to Teesside. The gas is transported in a separate pipeline to Ekofisk for further transport to Emden. The oil and gas production is metered to fiscal standards prior to pipeline transportation to Ekofisk. The metering systems are included in the Ekofisk system for distribution of hydrocarbons.

GYDA SØR

Production licence:	019 B	Block:	2/1
Operator:	BP Amoco Norge AS		
Licensees:			
AS Pelican			4.00000 %
BP Amoco Norge AS			56.00000 %
Den norske stats oljeselskap a.s (SDFI 30,000 %)			30.00000 %
Norske AEDC A/S			5.00000 %
Norske MOECO A/S			5.00000 %
Discovery well:	2/1-9	Year:	1991
Development approved:	1993	Prod.start:	1995
Recoverable reserves:		5.6	mill. Sm^3 oil
		3.7	bill. Sm^3 gas
		0.7	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		0.1 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		0 mill. [1)]	

1) Operating costs are included in Gyda

Production

Gyda Sør is produced using depressurization with the aid of two long-range wells from Gyda. No pressure communication has been observed between Gyda Sør and Gyda, although it is possible that there is pressure communication in the water zone.

Development

The well stream is treated on Gyda.

ULA

Production licence:	019, 019 B	Block:	7/12
Operator:	BP Amoco Norge AS		
Licensees:			
AS Pelican			5.00000 %
BP Amoco Norge AS			80.00000 %
Svenska Petroleum Exploration AS			15.00000 %
Discovery well:	7/12-2	ear:	1976
Development approved:	1980	rod.start:	1986
Recoverable reserves:		70.0	mill. Sm^3 oil
		3.7	bill. Sm^3 gas
		2.5	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		15.7 bill.	

Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:	374 mill.

Production

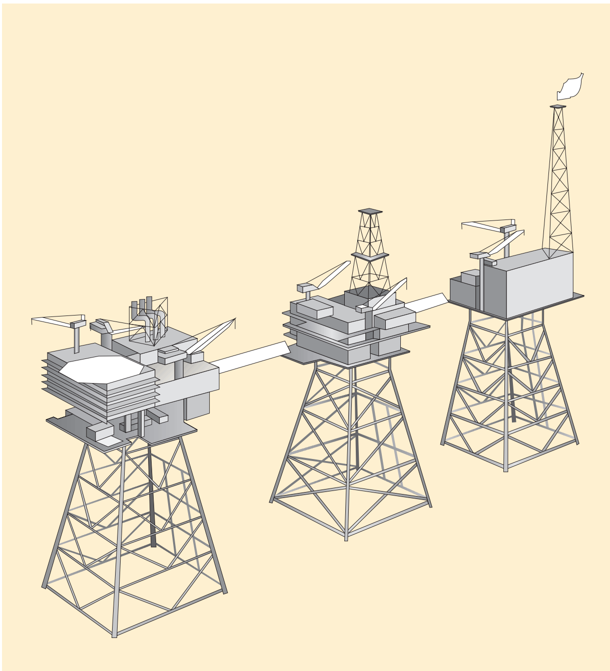
The main reservoir consists of Jurassic sandstone and is produced using water injection as the drive mechanism, see Figure 1.10.1. Currently, the production has a high and increasing water cut. The operator is continuously evaluating various measures to shut out the water. At the end of 1999, there were seven wells producing while six wells were used for water injection. In addition, one well is used for gas injection. In order to improve the exploitation of the remaining reserves, the operator plans to drill two new horizontal wells that will be used as producers.

Development

The development concept consists of three steel installations for production, drilling and living quarters, see Figure 1.10.6. Production capacity is currently 24,000 Sm^3 oil per day and 1.6 million Sm^3 gas per day. Water injection capacity is 32,000 m^3 per day. The capacity for treatment of produced water is approximately 19,000 m^3 per day.

The oil is transported by pipeline via Ekofisk to Teesside with Statoil as the operator of the pipeline. The gas is reinjected and the reinjection capacity is 1.4 million Sm^3 per day. The oil production is metered to fiscal standards prior to pipeline transportation to Ekofisk. The metering system is included in the Ekofisk system for distribution of hydrocarbons.

Figure 1.10.6
Installations on Ula



YME

Production licence:	114	Block:	9/2
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 30,000 %)			65.00000 %
RWE-DEA Norge AS			10.00000 %
Saga Petroleum ASA			25.00000 %
Discovery well:	9/2-1	Year:	1987
Development approved:	1995	Prod.start:	1996
	1995		
	1997		
	1998		
Recoverable reserves:		9.3	mill. Sm^3 oil
		0.0	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		2,3 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		837 mill.	

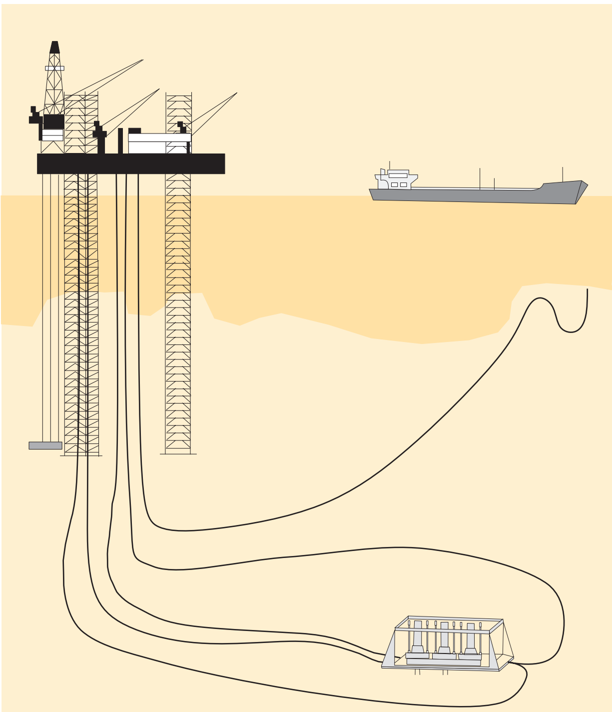
Production

Development of the Yme field, see Figure 1.10.1, was carried out in several phases. Oil is produced from the Gamma Vest, Gamma Sørøst, Beta Øst, Beta Vest Nord and Beta Vest Sør structures. The oil is found in the Sandnes formation, which belongs to the Middle to Late Jurassic Age.

The main reservoir on Yme is in the Gamma Vest structure. The reservoir is for the most part produced by depressurization, but water is injected in one well, and down-hole pumps are also used. Development of the deposits in Beta Øst was approved in November 1995. These deposits are produced with two subsea-completed wells. Depressurization with gas lift has been chosen as the drive mechanism. Development of the deposits in Gamma Sørøst was approved in February 1997. These deposits will be drained using depressurization.

The Beta Vest Nord discovery well 9/2-7 S commenced production on 1 September 1999. Exploration well 9/2-9 S proved oil in the Beta Vest Sør structure in September 1999. The well has been completed and reclassified as an oil producer. Both Beta Vest Nord and Beta Vest Sør are tied in to the Beta Øst subsea system.

Figure 1.10.7
Installations on Yme



Development

The field development concept consists of a jack-up installation and a storage tanker with buoy loading to shuttle tankers, Figure 1.10.7. The subsea installation on Yme Beta Øst is linked to Yme. There is no other infrastructure in the area. All oil from Yme is transported by ship to Mongstad for final separation of water and for fiscal metering.

The production installation has an oil production capacity of 8000 Sm^3 per day with the potential for upgrading. The gas treatment capacity is 800,000 Sm^3 gas per day, whereof 400,000 Sm^3 gas per day may be recirculated for gas lift.

VARG

Production licence:	038	Block:	15/12
Operator:	Saga Petroleum ASA		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 30,000 %)			65.00000 %
Saga Petroleum ASA			35.00000 %
Discovery well:	15/12-4	ear:	1984
Development approved:	1996	rod.start:	1998
Recoverable reserves:		4.4	mill. Sm^3 oil
		0.0	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		4.2 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		610 mill.	

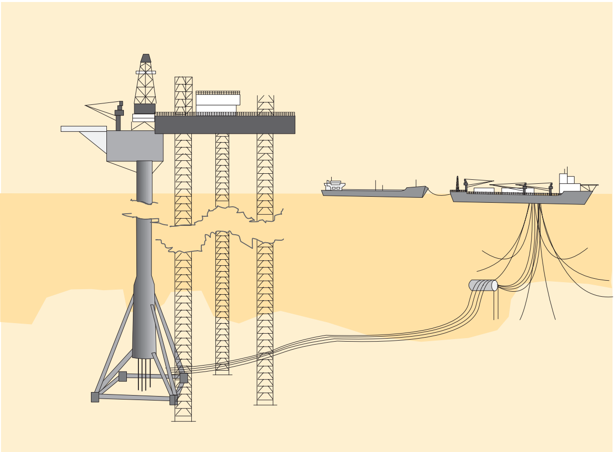
Production

The field contains oil in a greatly faulted sandstone reservoir from the Upper Jurassic Age, see Figure 1.10.9. The production strategy is based on the use of alternating water/gas injection (WAG). The total number of wells is estimated to be 13. Production started on 22 December 1998 and injection of water and gas started in early 1999.

Development

The plan for development and operation was approved in May 1996. Varg is developed with a production ship tied to a wellhead installation, see Figure 1.10.8. The wellhead installation was installed on the field in the summer of 1997, and pre-drilling of the production wells started at the end of 1997. The production ship anchored up on the field in the autumn of 1998. Planned production capacity is 9000 Sm^3 oil per day. The production ship was sold by the licensees and contracted to Varg in July 1999.

Figure 1.10.8
Installations on Varg



SLEIPNER AREA

Sleipner Øst, Sleipner Vest, Loke and Gungne have been approved for development in the Sleipner area, see Figure 1.10.9.

Agreements regarding coordinated operations, injection and sale have been signed for these fields. The production installations in the Sleipner area are shown on Figure 1.10.10. The gas is transported via pipeline, both to Zeebrügge in Belgium, through Statpipe/Norpipe and through the Europipe system to Emden in Germany. A small quantity of gas is sold to Ekofisk. The condensate is landed at Kårstø through a 250 km pipeline from Sleipner R to Kårstø.

Total produced gas and condensate are metered to fiscal standard on the field.

SLEIPNER ØST

Business area:	Sleipner Øst Unit		
Production licence:	046	**Block:**	15/9
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 29,600 %)			49.60000 %
Elf Petroleum Norge AS			10.00000 %
Esso Expl. and Prod. Norway A/S			30.40000 %
Norsk Hydro Produksjon AS			10.00000 %
Discovery well:	15/9-9	ear:	1981
Development approved:	1986	rod.start:	1993
Recoverable reserves:		0.0	mill. Sm^3 oil
		38.5	bill. Sm^3 gas
		9.7	mill. tonnes NGL
		21.3	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		28.1 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		602 mill.	

Production

Sleipner Øst contains gas and condensate in the Ty and Hugin formation from the Tertiary and Jurassic Age respectively. Some gas has also been proven in the underlying formations of Cretaceous and Triassic Age. The gas contains a relatively high amount of condensate. The Tertiary reservoir in Sleipner Øst is produced using injection of dry gas in order to extract more condensate than is achieved through depressurization, while depressurization is used for the Jurassic reservoir. Drilling of new production and injection wells has been postponed from 1999 to 2000. Arrangements were made for limited low-pressure production on Sleipner Øst in 1999.

Development

Sleipner Øst was developed with an integrated process, drilling and living quarters installation with a concrete substructure (Sleipner A). In addition, a separate riser installation has been built (Sleipner R) with a gangway to Sleipner A. A subsea template has been installed for draining of the northern part of Sleipner Øst.

LOKE

Business area:	Sleipner Øst Unit		
Production licence:	046	**Block:**	15/9
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 29,600 %)			49.60000 %
Elf Petroleum Norge AS			10.00000 %
Esso Expl. and Prod. Norway A/S			30.40000 %
Norsk Hydro Produksjon AS			10.00000 %
Discovery well:	15/9-17	Year:	1983
Development approved:	1991	Prod.start:	1998
	1995		
Recoverable reserves:		0.0	mill. Sm^3 oil
		3.5	bill. Sm^3 gas
		0.5	mill. tonnes NGL
		1.2	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		1.1 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		12 mill.	

Production

Loke contains gas and condensate in the Ty and Hugin/Skagerrak formations from the Tertiary and Jurassic/Triassic Age respectively (called Loke Triassic). The field is produced using depressurization. Production from the Tertiary reservoir was shut down in 1997. The well was extended for production from the Triassic reservoir in 1998. Production commenced in June 1998, but due to corrosion in a pipeline, was shut down after two weeks. Production recommenced in August 1999.

Development

Loke was developed using a subsea template tied in to Sleipner A. Due to corrosion in the pipeline between the subsea template and Sleipner A, a new pipeline was laid in 1999. A new exploration well is planned for 2000 in order to prove additional resources.

Figure 1.10.9
Fields and discoveries in the Sleipner area

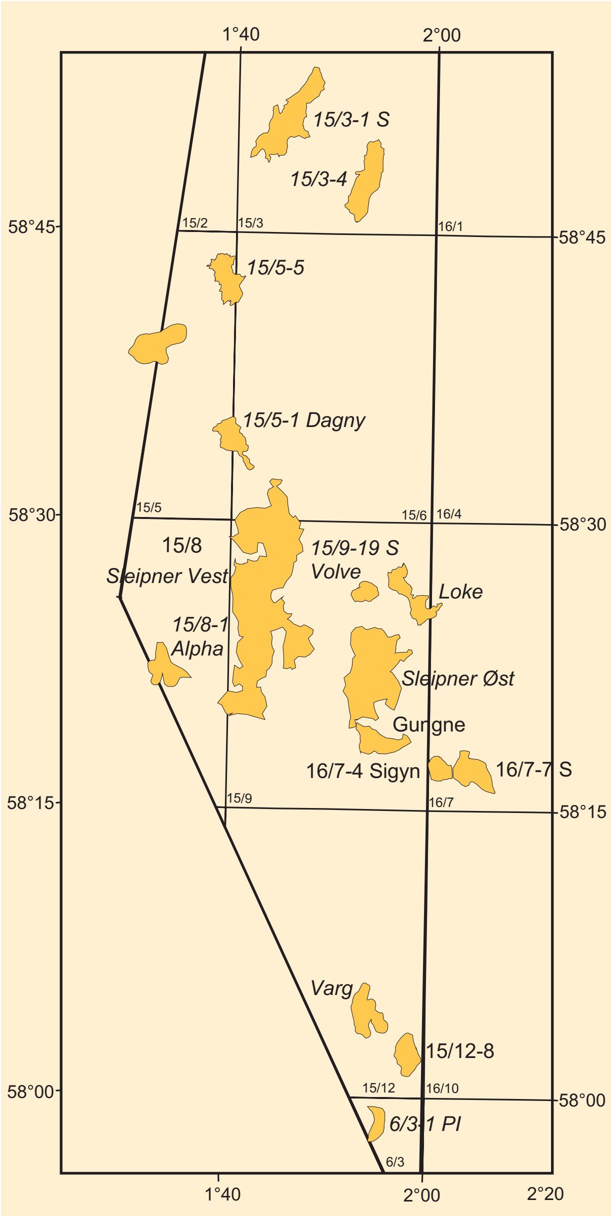
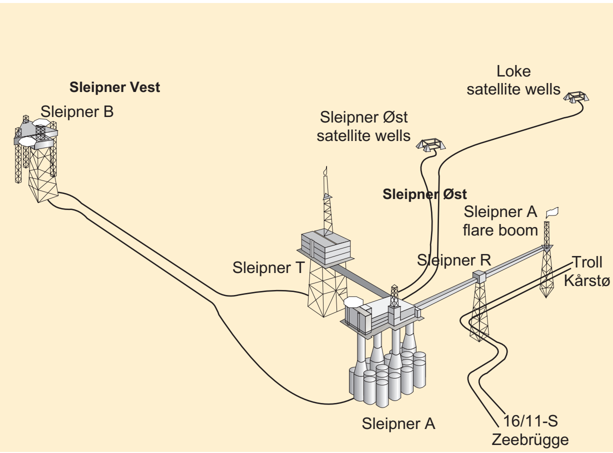


Figure 1.10.10
Installations in the Sleipner area



GUNGNE

Production licence:	046	**Block:**	15/9
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 34,400 %)			52.60000 %
Elf Petroleum Norge AS			10.00000 %
Esso Expl. and Prod. Norway A/S			28.00000 %
Norsk Hydro Produksjon AS			9.40000 %
Discovery well:	15/9-15	ear:	1982
Development approved:	1995	rod.start:	1996
Recoverable reserves:		0.0	mill. Sm^3 oil
		8.4	bill. Sm^3 gas
		1.0	mill. tonnes NGL
		3.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		0.6 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		22 mill.	

Production
Gungne contains gas and condensate in the Skagerrak formation of the Triassic Age. The field is produced using depressurization.

Development
Gungne is produced with one well from Sleipner A. Drilling of a new production well has been postponed from 1999 to 2000.

SLEIPNER VEST

Business area:	Sleipner Vest Unit		
Production licence:	029, 046	**Block:**	15/6, 15/9
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 32,375 %)			49.50291 %
Elf Petroleum Norge AS			9.41120 %
Esso Expl. and Prod. Norway A/S			32.23936 %
Norsk Hydro Produksjon AS			8.84653 %
Discovery well:	15/6-3	Year:	1974
Development approved:	1992	Prod.start:	1996
Recoverable reserves:		0.0	mill. Sm^3 oil
		125.5	bill. Sm^3 gas
		8.5	mill. tonnes NGL
		27.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		23.1 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		457 mill.	

Production
The field contains gas/condensate with an underlying layer of oil in some areas. The reservoir lies in the Hugin formation from the Jurassic Age. The field consists of several fault blocks and the communication conditions in the reservoir are uncertain.

Gas/condensate is produced using depressurization and pressure maintenance from the underlying water zone. So far, it has been impossible to find a profitable concept for producing the oil. Dry gas not needed for meeting sales obligations, has been injected in Sleipner Øst. The gas in Sleipner Vest contains up to 9 volume per cent CO_2, which is separated from the gas and injected into a sand layer in the Utsira formation.

Development

The first phase of the development of Sleipner Vest includes a wellhead installation, Sleipner B, and an installation for processing and removal of CO_2, Sleipner T. Sleipner B is located in the southern part of Sleipner Vest. The wells have been drilled from the drilling installation West Epsilon, which has been positioned by Sleipner B. From Sleipner B, the well stream is routed to Sleipner T, which has a gangway to Sleipner A. These installations use common utilities.

Phases 2 and 3 comprise development of the northern part of Sleipner Vest, as well as increased capacity for compression of gas for export. Extensive studies have been carried out in 1999 regarding solutions for and timing of the compression capacity.

In 1999, it was decided to temporarily increase the export capacity of Sleipner Vest from 20.7 million to 22.6 Sm^3 export gas per day. Over the short term, this provides for more gas available for sale and injection in Sleipner Øst, as well as earlier production of condensate. In addition, measures were implemented to improve the facility for separation of CO_2 from the gas, with additional measures planned for 2000. Some modifications have been carried out on Sleipner B in order to prepare for unmanned operation. Unmanned operation will only be relevant when the drilling phase has been completed. As of 31 December 1999, the drilling plan includes all of 2000 with the possibility for additional extensions.

BALDER

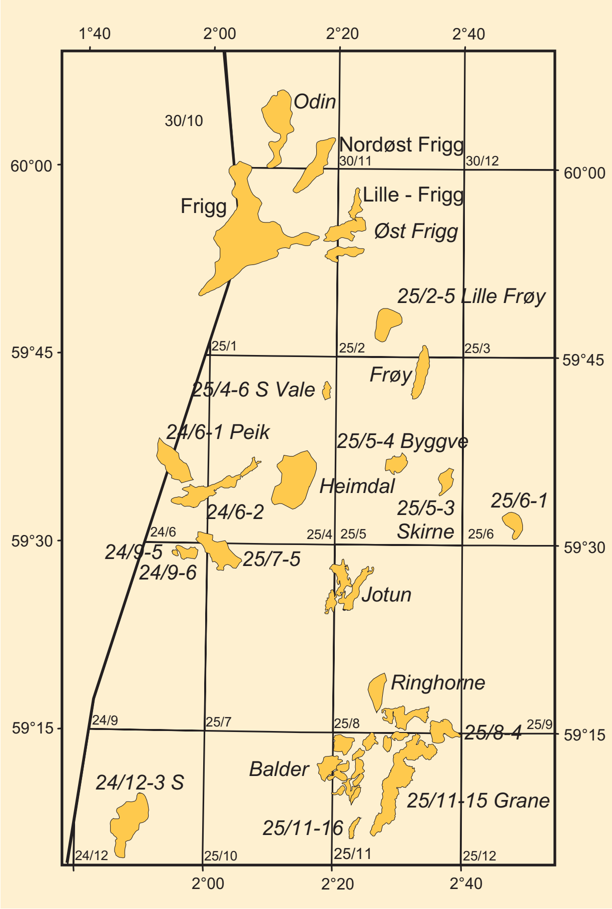
Production licence:	001	**Block:**	25/11
Operator:	Esso Expl. and Prod. Norway A/S		
Licensees:			
Esso Expl. and Prod. Norway A/S			100.00000 %
Discovery well:	25/11-1	ear:	1967
Development approved:	1996	rod.start:	1999
Recoverable reserves:		26.7	mill. Sm^3 oil
		0.0	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		9.8 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		267 mill.	

Production

The Balder reservoir is sandstone from the Tertiary Age. It is poorly consolidated, but has good reservoir properties and contains relatively viscous oil. The Balder field, see Figure 1.10.11, consists of several separate structures.

Production from the Balder field commenced in September 1999 with production from ten wells. The field will be produced using natural water drive and water injection. All produced water will be reinjected. In addition, a well has been drilled for production of injection water. Produced gas will be reinjected in a well on the field.

Figure 1.10.11
Fields and discoveries in the Frigg, Jotun and Balder area

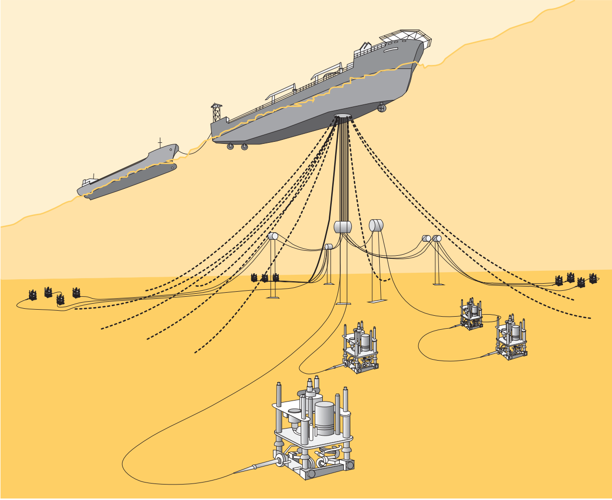


Development

The Balder field has been developed using subsea-completed wells tied in to a production and storage ship, see Figure 1.10.12. The oil will be exported via tankers.

Planned average plateau production of oil is 11,900 Sm^3 per day.

Figure 1.10.12
Installations in the Balder area



JOTUN

Business area:	Jotun Unit			
Production licence:	027 B, 103 B	**Block:**	25/7, 25/8	
Operator: Esso Expl. and Prod. Norway A/S				
Licensees:				
Amerada Hess Norge AS			1.25000 %	
Den norske stats oljeselskap a.s (SDFI 3,000 %)			5.00000 %	
Enterprise Oil Norwegian AS			45.00000 %	
Esso Expl. and Prod. Norway A/S			45.00000 %	
Norske Conoco A/S			3.75000 %	
Discovery well:	25/8-5 S	ear:	1994	
Development approved:	1997	rod.start:	1999	
Recoverable reserves:		31.1	mill. Sm^3 oil	
		1.0	bill. Sm^3 gas	
		0.0	mill. tonnes NGL	
		0.0	mill. Sm^3 cond.	
Total investments (firm 1999-NOK):		8.8 bill.		
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		152 mill.		

Production

Jotun, see Figure 1.10.11, comprises the discoveries 25/8-5 S, 25/7-3 and 25/8-8 S, all of which were made in 1994 and 1995. In all of the structures, oil was found in the Heimdal formation from the Paleocene Age. In the 25/8-8 S discovery, some free gas was also proven. The majority of the resources lie in Production License 027B. An agreement concerning unitization between the two production licences was signed in the autumn of 1997. Water injection, possibly in combination with natural water drive, is the drive mechanism.

Jotun commenced production in September 1999. A total of 11 oil producers, six water injectors and two water producers are planned on the field. Drilling of the production wells is in progress, and four wells were producing at the end of 1999.

Figure 1.10.13
Installations on Jotun

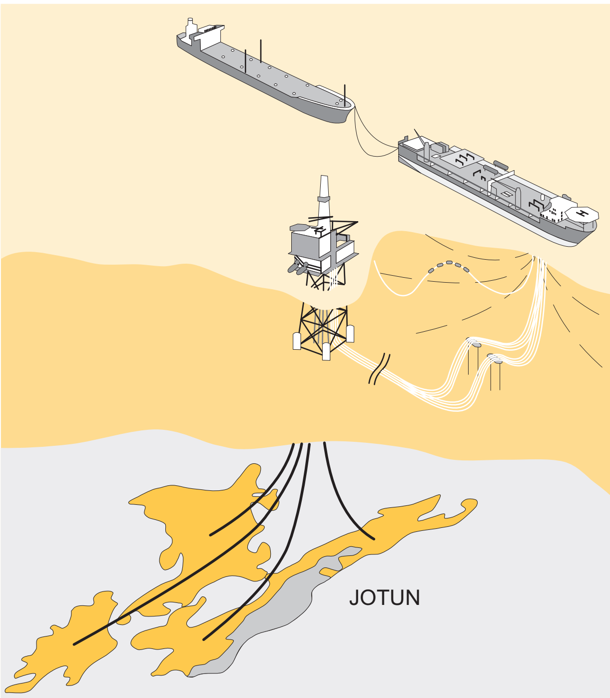
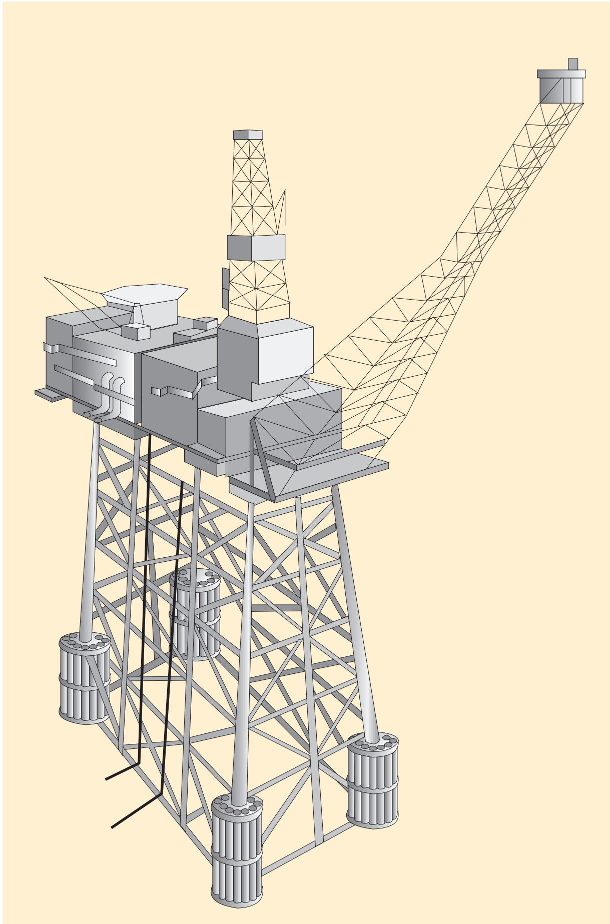


Figure 1.10.14
Installation on Heimdal



Development

The development concept consists of a wellhead installation and a production vessel, see Figure 1.10.13. The wellhead installation was positioned on the field in August 1998. The oil will be loaded on the field and the gas exported via Statpipe.

HEIMDAL

Business area:	Heimdal Unit			
Production licence:	036	**Block:**	25/4	
Operator: Norsk Hydro Produksjon AS				
Licensees:				
AS Ugland Rederi			0.16900 %	
Den norske stats oljeselskap a.s (SDFI 20,000 %)			40.00000 %	
Elf Petroleum Norge AS			11.93900 %	
Marathon Petroleum Norge AS			23.79800 %	
Norsk Hydro Produksjon AS			15.80300%	
Saga Petroleum ASA			3.47100%	
Total Norge AS			4.82000%	
Discovery well:	25/4-1	ear:	1972	
Development approved:	1981	rod.start:	1985	

	1992		
	1999		
Recoverable reserves:		6.9	mill. Sm^3 oil
		44.6	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		16.6 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		233 mill.	

Production

The field, see Figure 1.10.11, produces from sandstone in the Heimdal formation. Nine production wells and one observation well have been drilled. The field has been shut down since the summer of 1999 in order to modify the installation.

Development

The Heimdal field was developed with an integrated steel jacket structure with drilling, production and living quarters functions, see Figure 1.10.14.The deliveries of gas via Emden began in February 1986.

The gas from the Heimdal field is transported in Statpipe. The pipeline from Heimdal is tied into the Statpipe system at the Draupner riser platform. The condensate is transported from Heimdal to Brae in the British sector through a separate pipeline. From the Brae field the condensate goes to Cruden Bay in Scotland.

After a modification phase from 1999 to 2000, the installation will once again be put into operation for producing the remaining reserves in the field and for processing of the gas from 30/2-1 Huldra. A riser installation will also be built, which will be able to take in risers from other discoveries and transportation systems in the area.

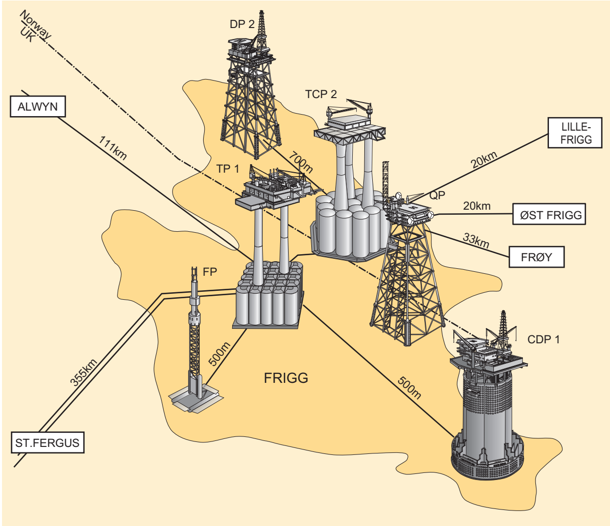
FRIGG

Business area:	Frigg Unit		
Production licence:	024	**Block:**	25/1
Operator:	Elf Petroleum Norge AS		
Licensees:			
Norwegian part (60.82)			
Den norske stats oljeselskap a.s			12.16400 %
Elf Petroleum Norge AS			16.06800 %
Norsk Hydro Produksjon AS			19.99200 %
Total Norge AS			12.59600 %
British part (39.18%)			
Elf Exploration UK Ltd			26.12000 %
Total Oil Marine Ltd			13.06000 %
Discovery well:	25/1-1	ear:	1971
Development approved:	1974	rod.start:	1977
Recoverable reserves:		0.0	mill. Sm^3 oil
		119.8	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.4	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		30.5 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		364 mill.	

Production

The field, see Figure 1.10.11, produces gas from the Frigg formation, which consists of sandstone from the Eocene Age. The production wells on CDP1, see Figure 1.10.15, are permanently plugged. On DP2, the wells have reduced production potential due to water influx. Future development of produced water volume will be a crucial factor in determining when the field will be shut down. According to current plans, the last year of production will be 2002.

Figure 1.10.15
Installations in the Frigg area



Development

The field was developed in three phases. Phase I consists of one production and one treatment installation on the British part of the field, as well as a living quarters installation (CDP1, TP1 and QP). Production from Phase I started in 1977.

Phase II consists of one production and one treatment installation located on the Norwegian part of the field (DP2 and TCP2). Production from Phase II started in 1978. Figure 1.10.15 shows the installations in the Frigg area.

Phase III of the development comprises the installation of three turbine-driven compressors on TCP2. The compressor system is necessary in order to compensate for reduced reservoir pressure. These facilities were put into operation in the autumn of 1981.

In 1995, a new module was installed on TCP2 in order to treat oil and gas from Frøy. Prior to their shutdown, gas from Nordøst Frigg, Øst Frigg, Lille-Frigg and Odin was also treated on Frigg. Transportation of gas from the Alwyn North field on the British side takes place via TP1.

TP1 has been converted from a processing installation to a riser installation. The gas is transported 355 km to St. Fergus in Scotland via two pipelines, each with a diameter of 813 millimeters. The liquid is transported in Frostpipe via Oseberg to Stura.

FRØY

Business area:	Frøy Unit		
Production licence:	026, 102	**Block:**	25/2, 25/5
Operator:	Elf Petroleum Norge AS		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 41.616 %)			53.96000 %
Elf Petroleum Norge AS			24.75730 %
Norsk Hydro Produksjon AS			6.04810 %
Total Norge AS			15.23460 %

Discovery well:	25/5-1	Year:	1987
Development approved:	1992	Prod.start:	1995
Recoverable reserves:		5.5	mill. Sm^3 oil
		1.6	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.1	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		6.6 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		142 mill.	

Production

Frøy, see Figure 1.10.11, is an oilfield that produces from the Brent group of the Late Jurassic Age. The production strategy is based on water injection. The field has 10 wells, of which six are production wells. The field is currently producing from three wells. Today Frøy has low production and relatively high operating costs. The plan is to produce until the summer of 2000.

Development

The field was developed by means of a wellhead installation. Oil and gas are transferred in separate pipelines to Frigg for further processing and metering. The gas is transported on to St. Fergus. The oil is transported in Frostpipe to Oseberg, and from there on to the oil terminal at Stura.

OSEBERG AREA

OSEBERG

Business area:	Oseberg Unit		
Production licence:	053, 079	**Block:**	30/6, 30/9
Operator:	Norsk Hydro Produksjon AS		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 50.784 %)			64.78379 %
Elf Petroleum Norge AS			5.76959 %
Mobil Development Norway AS			4.32720 %
Norsk Hydro Produksjon AS			13.68186 %
Saga Petroleum ASA			8.55276 %
Total Norge AS			2.88480 %
Discovery well:	30/6-1	ear:	1979
Development approved:	1984	rod.start:	1988
	1988		
	1996		
Recoverable reserves:		337.0	mill. Sm^3 oil
		34.0	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		7.5	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		61.6 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		1.4 mill.	

Production

The field consists of several reservoirs in the Brent group (Middle Jurassic), divided among three structures. Figure 1.10.16 shows fields and discoveries in the Oseberg area. The main reservoirs are in the Oseberg and Tarbert formations, but the Etive and Ness formations are also important contributors. The reservoir had an initial gas cap over the oil zone. The use of horizontal production wells was not included in the original plans, but most of the production wells are now drilled horizontally with good results. The reservoir pressure in Oseberg is maintained through gas injection, water injection and WAG. The injection gas is imported from Troll Øst (TOGI) and Oseberg Vest. There are approx. 70 operative wells on the field including injection wells.

Development

The oil part of the Oseberg field has been developed in two phases, see Figure 1.10.17. Phase I is developed with a field center in the south with two installations. Oseberg A comprises a processing and living quarters installation with a concrete gravity base structure, and Oseberg B comprises a drilling and water injection installation with a steel jacket. Average oil processing capacity is about 55,000 Sm³ per day.

Phase II comprised development of the northern part of the field. The Oseberg C installation is an integrated production, drilling and living quarters installation (PDQ). Average oil processing capacity is about 23,000 Sm³ per day.

The gas phase (Phase III) has been developed with Oseberg D tied in to the rest of the field center. The installation, for processing of dry gas, has a capacity of 10 billion Sm³ per year and became operational in October 1999. Fiscal metering stations for gas and condensate have been installed. Initially, the facility will be used to recycle the gas in the reservoir in order to provide increased oil/condensate production. Gas export will commence 1 October 2000 through a new pipeline to the Statpipe system via the Heimdal installation.

Oseberg A and Oseberg C are fitted with metering stations for fiscal metering of stabilized oil prior to pipeline transportation to the Sture Terminal. Purchase of injection gas from Troll (TOGI) is metered via the fiscal gas metering station installed on Oseberg A. Stabilized oil is exported from the terminal at Sture via two quay facilities which are linked to two identical fiscal oil metering stations.

Figure 1.10.16
Fields and discoveries in the Oseberg area

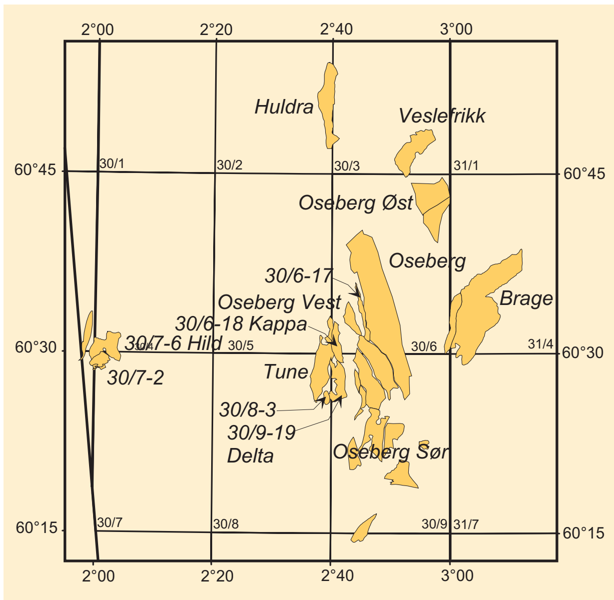
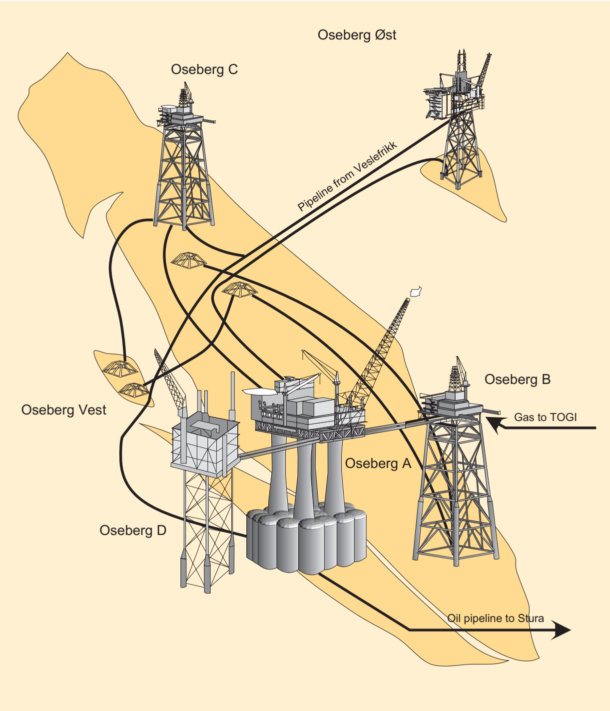


Figure 1.10.17
Installations on Oseberg



OSEBERG VEST

Business area:	Oseberg Unit			
Production licence:	053	**Block:**	30/6	
Operator:	Norsk Hydro Produksjon AS			
Licensees:				
Den norske stats oljeselskap a.s (SDFI 50.784 %)			64.78379 %	
Elf Petroleum Norge AS			5.76959 %	
Mobil Development Norway AS			4.32720 %	
Norsk Hydro Produksjon AS			13.68186 %	
Saga Petroleum ASA			8.55276 %	
Total Norge AS			2.88480 %	
Discovery well:	30/6-15	Year:	1984	
Development approved:	1988	Prod.start:	1991	
Recoverable reserves:		1.6	mill. Sm^3 oil	
		6.0	bill. Sm^3 gas	
		0.0	mill. tonnes NGL	
		0.0	mill. Sm^3 cond.	
Total investments (firm 1999-NOK):		0.9 bill.		
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		0 mill.		

Production

Oseberg Vest consists of a rotated fault block where the reservoir zones are located in the Statfjord formation of the Lower Jurassic.

A coal-bearing shale zone divides the Statfjord formation into an upper and a lower reservoir zone. Gas was proven first with a thin oil zone in the upper reservoir zone. In order to produce as much of the oil as possible, a production solution with two horizontal production wells was chosen. In connection with the drilling of the first production well, oil was discovered in the lower reservoir zone. The field is produced with depressurization, but has natural pressure support from the gas cap.

Development

The field was developed with two horizontal production wells. The first production well, which started producing in 1991, is tied to Oseberg C, while the second well, completed in 1996, is tied to Oseberg B. All produced gas is injected into the Oseberg field.

OSEBERG ØST

Production licence:	053	**Block:**	30/6	
Operator:	Norsk Hydro Produksjon AS			
Licensees:				
Den norske stats oljeselskap a.s (SDFI 45.400 %)			59.40000 %	
Elf Petroleum Norge AS			9.33300 %	
Mobil Development Norway AS			7.00000 %	
Norsk Hydro Produksjon AS			12.25000 %	
Saga Petroleum ASA			7.35000 %	
Total Norge AS			4.66700 %	
Discovery well:	30/6-5	ear:	1981	
Development approved:	1996	rod.start:	1999	
Recoverable reserves:		22.8	mill. Sm^3 oil	
		0.8	bill. Sm^3 gas	
		0.0	mill. tonnes NGL	
		0.0	mill. Sm^3 cond.	
Total investments (firm 1999-NOK):		4.8 bill.		
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		221 mill.		

Production

The field consists of two structures that are separated by a sealed fault. Both structures contain several oil-bearing layers within the Brent group (Middle Jurassic) with varying porosity and permeability, as well as several different oil/water contacts. The intention is to maintain pressure with the aid of water and WAG injection. The field will be produced with six production, six injection and two water production wells.

Development

The field has been developed with an installation with living quarters, drilling equipment and first stage separation of oil, water and gas. Processing will be completed at the Oseberg field center. The installation has the capacity to process 12,000 Sm^3 oil and 13,300 m^3 water per day. The maximum gas injection rate is 1.4 million Sm^3 per day. Fiscal metering of oil production takes place on the field. The oil from the field is transported in the Oseberg Transport System to Stura. Production commenced in May 1999.

OSEBERG SØR

Business area:	Oseberg Sør Unit			
Production licence:	079, 104, 171	**Block:**	30/12, 30/9	
Operator:	Norsk Hydro Produksjon AS			
Licensees:				
Den norske stats oljeselskap a.s (SDFI 38.360 %)			56.58000 %	
Mobil Development Norway AS			3.70000 %	
Norsk Hydro Produksjon AS			21.88000 %	
Norske Conoco A/S			7.70000 %	
Saga Petroleum ASA			10.14000 %	
Discovery well:	30/9-3	ear:	1984	
Development approved:	1997	rod.start:	2000	

Recoverable reserves:	53.5	mill. Sm^3 oil
	11.4	bill. Sm^3 gas
	0.0	mill. tonnes NGL
	0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):	9.4 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:	61 mill.	

Production

Ten potential reservoir structures lie within the area defined by the operator as Oseberg Sør. Seven of these are incorporated in the basic estimates for Oseberg Sør. Hydro is the operator and the field has been unitized. Most of the reserves lie in the Brent Group (Middle Jurassic), but discoveries have also been made in the Heather and Draupne formations (Upper Jurassic). The production mechanism is different for the various structures. The plan is to use water injection, gas injection and WAG injection for pressure maintenance. The plan is to drill 16 production wells, 14 injection wells and three water production wells.

Development

The field is being developed with an installation with living quarters, drilling module and first stage separation of oil and gas. The installation will have the capacity to process 14,900 Sm^3 oil and 13,000 m^3 water per day with fiscal metering of the oil. Processing will be completed at the Oseberg field center. The oil will be transported in the Oseberg Transport System to Sture. Some of the reservoirs will be drilled with wells from two subsea templates that will be tied in to the installation with pipelines. A part of the Omega Nord structure can be reached by wells from the Oseberg field center, and will be produced and metered from there. Production from Omega Nord will commence in February 2000, while the Oseberg Sør installation will start producing in September 2000.

TUNE

Production licence:	034, 053, 190	**Block:**	30/5, 30/6, 30/8
Operator:	Norsk Hydro Produksjon AS		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 50.000 %)			50.00000 %
Elf Petroleum Norge AS			10.00000 %
Norsk Hydro Produksjon AS			30.00000 %
Total Norge AS			10.00000 %
Discovery well:	30/8-1 S	ear:	1995
Development approved:	1999	rod.start:	2002
Recoverable reserves:		0.0	mill. Sm^3 oil
		24.0	bill. Sm^3 gas
		0.1	mill. tonnes NGL
		6.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		2.6 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		0 mill.	

30/8-1 S Tune is a gas/condensate discovery that lies 12 km to the west of the Oseberg field center. Tune, see Figure 1.10.16, consists of two main structures; the A and B structures. Gas/condensate has been proven in the A structure.

The plan for development and operation was approved in December 1999. The plan is to develop Tune in two phases with a subsea development with transportation of the well stream to Oseberg. The field has been allocated gas based on development of the A structure.

BRAGE

Business area:	Brage Unit		
Production licence:	053 B, 055, 185	**Block:**	30/6, 31/4, 31/7
Operator:	Norsk Hydro Produksjon AS		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 34.257 %)			46.95670 %
Esso Expl. and Prod. Norway A/S			16.34340 %
Fortum Petroleum AS			12.25750 %
Norsk Hydro Produksjon AS			24.44240 %
Discovery well:	31/4-3	Year:	1980
Development approved:	1990	Prod.start:	1993
	1998		
Recoverable reserves:		46.7	mill. Sm^3 oil
		2.6	bill. Sm^3 gas
		0.7	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		13.7 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		396 mill.	

Production

Oil has been proven in two formations in the unitized part of Brage, see Figure 1.10.16: the Statfjord formation (Early Jurassic) and the Fensfjord formation (Late Jurassic). Oil and gas have been proven in the Sognefjord formation (Late Jurassic).

The current production strategy for Brage is pressure maintenance with water injection for the Statfjord formation and both water and WAG injection for the Fensfjord formation. Production from Brage started in 1993 and has been declining since 1998.

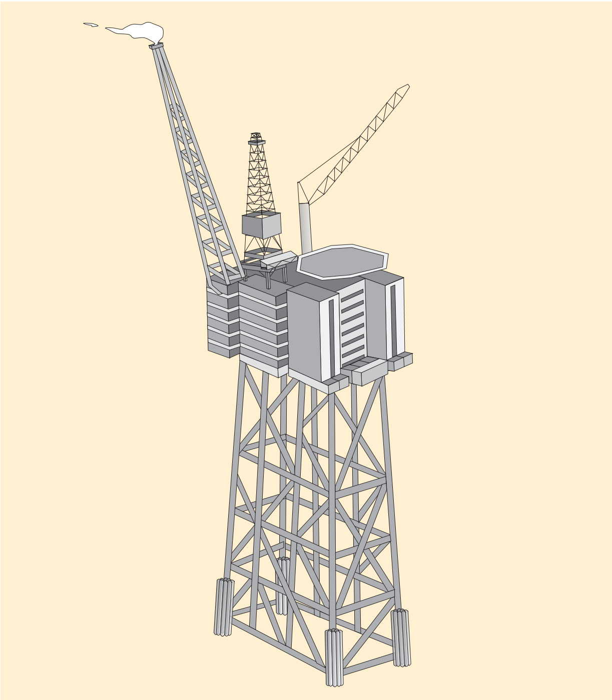
Test production from the Sognefjord formation was started in the autumn of 1997. The plan for development and operation for the deposits in the Sognefjord formation was submitted and approved in October 1998. A production well has been drilled in this formation, but has not been in operation since early 1999.

Development

The Brage field has been developed with an integrated production, drilling and living quarters installation with a steel jacket, see Figure 1.10.18. The oil is transported via pipeline to Oseberg and on through the Oseberg pipeline to the Sture Terminal. A pipeline for gas is connected to Statpipe.

The field has a total of 34 wells, of which 21 are oil producers, five water producers/injectors and six WAG injectors. There has been no drilling on Brage since March 1999 due to low oil prices and high economic risk associated with new wells. New drilling is expected in 2000.

Figure 1.10.18
Installation on Brage



VESLEFRIKK

Production licence:	052, 053	**Block:**	30/3, 30/6
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 37.000 %)			55.00000 %
Norske RWE-DEA AS			2.25000 %
Petro-Canada Norge AS			9.00000 %
RWE-DEA Norge AS			11.25000 %
Svenska Petroleum Exploration AS			4.50000 %
Total Norge AS			18.00000 %
Discovery well:	30/3-2 R	Year:	1981
Development approved:	1987	Prod.start:	1989
	1994		
	1994		
	1994		
	1999		
Recoverable reserves:		54.5	mill. Sm^3 oil
		9.6	bill. Sm^3 gas
		1.3	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		14.2 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		1033 mill.	

Production

The field, see Figure 1.10.16, produces from reservoirs in the lower part of the Brent group and the Dunlin group (Intra Dunlin Sand) and the Statfjord formation.

The current production strategy for Veslefrikk is pressure maintenance with water injection in the Brent group, dry gas injection in the Statfjord formation and WAG injection in the Dunlin group.

Production from the Statfjord formation started in 1997. The reservoir has a gas cap and a higher content of associated gas than the other reservoirs.

A small discovery was made during the drilling of well 30/3-7 S in 1995. The well was tested in 1997. Well 30/3-7 B is the third track of well 30/3-7. Test production from the well started in 1998. The results will be tested in January 2000.

Development

The field has been developed with a permanent wellhead installation with a steel jacket and a semi-submersible installation with process facilities and living quarters, see Figure 1.10.19. The semi-submersible installation is connected to the permanent wellhead installation. The field has 14 production wells, five water injection wells, two WAG injection wells and one gas injector.

An oil pipeline is connected to the Oseberg Transport System for transport to the Sture Terminal. Gas is transported via the Statpipe system.

It has been decided that the gas from Huldra will be routed via Veslefrikk to the Statpipe pipeline. The semi-submersible installation was towed to Aker Stord where necessary modifications as well as an upgrade were performed. This entailed a complete shutdown of production on Veslefrikk during June-August, as well as only 50% production in September.

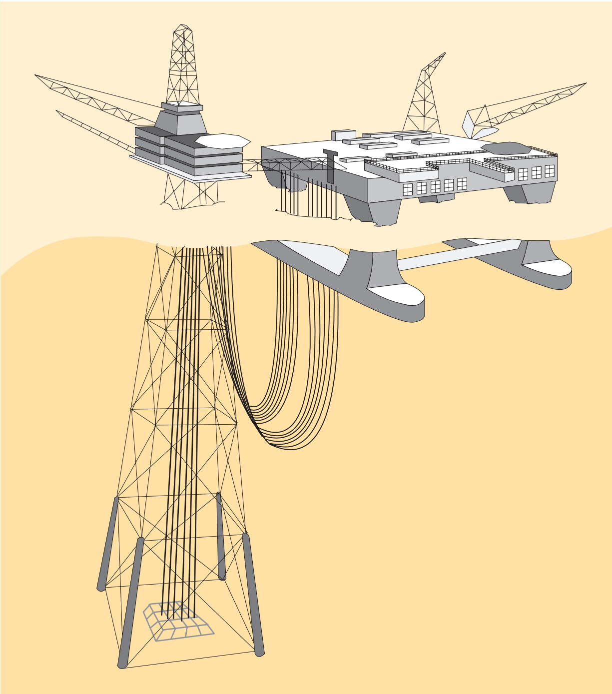
HULDRA

Business area:	Huldra Unit		
Production licence:	051, 052	**Block:**	30/2, 30/3
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 31.955 %)			51.62011 %
Norske Conoco A/S			23.33625 %
Petro-Canada Norge AS			0.49788 %
Svenska Petroleum Exploration AS			0.21375 %
Total Norge AS			24.33201 %
Discovery well:	30/2-1	Year:	1982
Development approved:	1999	Prod.start:	2001
Recoverable reserves:		0.0	mill. Sm^3 oil
		18.6	bill. Sm^3 gas
		0.3	mill. tonnes NGL
		7.4	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		5.8 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		0 mill.	

Huldra is a gas discovery that lies to the northwest of Veslefrikk, see Figure 1.10.16. Gas has been proven in the Brent group of the Middle Jurassic Age. Structurally, the Huldra discovery consists of a rotated fault block that slopes to the east. Under the main reservoir, there is a prospect in the Statfjord formation that will be drilled. Huldra has been granted gas allocation with planned production start-up in the year 2001.

The plan for development and operation of the Huldra discovery and the plan for installation and operation of the pipelines have been approved. The Huldra discovery is being developed with a permanent, unmanned installation. Drilling is planned with a jack-up installation. Six production wells have been planned. After first stage separation, gas and condensate will be transported to Heimdal and Veslefrikk respectively for final processing.

Figure 1.10.19
Installations on Veslefrikk



TROLL

Business area:	Troll Unit			
Production licence:	054, 085	**Block:**	31/2, 31/3, 31/5, 31/6	
Operator:	Norsk Hydro Produksjon AS, Den norske stats oljeselskap a.s			
Licensees:				
A/S Norske Shell				8.10145 %
Den norske stats oljeselskap a.s (SDFI 62.928 %)				76.80468 %*
Elf Petroleum Norge AS				2.34548 %
Norsk Hydro Produksjon AS				7.71753 %
Norske Conoco A/S				1.62374 %
Saga Petroleum ASA				2.06164 %
Total Norge AS				1.34548 %
Discovery well:	31/2-1	Year:	1979	
Development approved:	1986	Prod.start:	1995	
	1992			
	1994			
	1996			
	1997			
	1999			
Recoverable reserves:		195.0	mill. Sm^3 oil	
		653.3	bill. Sm^3 gas	
		12.7	mill. tonnes NGL	
		0.0	mill. Sm^3 cond.	
Total investments (firm 1999-NOK):		68.7 bill.		
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		726 mill.		

* Subject to approval by the Ministry of Finance

Structurally, the Troll field lies on the northwestern part of the Horda platform, see Figure 1.10.20. The field consists of three relatively large, rotated fault blocks with an easterly slope and extend over an area of 750 km². The water depth in the area is over 300 meters. The hydrocarbon-bearing layers are mainly sandstone of the Sognefjord formation, from the Middle to Late Jurassic Age. The field's gas column, which is more than 200 meters thick in the east, diminishes to the west, while the oil column drops from 22-26 meters in the west to 0-4 meters in the east. The development of the field has taken place in several phases. The Troll field was unitized in 1986.

In addition to the reported recoverable oil reserves, significant potential additional resources have been identified in Troll Vest.

TOGI

The subsea system Troll Oseberg Gas Injection (TOGI) is controlled from the Oseberg Field Center and produces gas from Troll Øst for injection in the Oseberg field. Production and delivery of gas via TOGI started in February 1991. Up to the end of 1998, TOGI had delivered 19.4 billion Sm^3 gas to Oseberg. There has been no production from TOGI in 1999. It is expected that production will resume in 2000. Norsk Hydro was responsible for the development of TOGI and is the operator in the operations phase.

Troll Phase I: Development of the gas reserves in Troll Øst

Production

A/S Norske Shell was the development operator for Troll Phase I. Statoil assumed the role of operator for the operation of Troll Phase I in June 1996. During the course of 1998, the last of a total of 39 gas production wells had been completed on Troll Øst.

Regular gas deliveries from Troll started on 1 October 1996. The gas is delivered to various customers on the Continent. Only part of the gas in the field has been sold. Due to internal pressure communication in the field, gas production from Troll Øst may have a substantial effect on future production of oil from Troll Vest. Therefore, great emphasis is placed on finding an optimal production strategy for oil and gas for the entire Troll field. In the autumn of 1998, a working group was established for the purpose of evaluating the production strategy for Troll. The working group consists of representatives from the operators, Statoil and Norsk Hydro, as well as the Norwegian Petroleum Directorate. The working group presented a report in 1999. Evaluation of the report and further studies are still in progress.

Development

The gas reserves in Troll Øst are produced from Troll A, which is a permanent wellhead installation with a concrete gravity base structure. The gas from Troll Øst and Troll Vest is transported from Troll A via two multi-phase pipelines to the gas treatment facility at Kollsnes. At the land facility, the condensate is separated from the gas and transported through a pipeline to the Sture Terminal. Condensate owned by Hydro and Elf is then exported to the market, while the rest of the condensate is sent via a pipeline to Mongstad for further processing. The condensate will be flow-metered in a fiscal metering station before it leaves the Kollsnes Terminal. The dry gas will be compressed and exported via pipeline to the Continent.

The Kollsnes facility has an export capacity of 100 million Sm^3 gas per day. Metering of the gas to fiscal standard takes place through two identical metering stations for Zeepipe II A and II B. Each metering station has a capacity of about 58.8 million Sm^3 per day. The gas treatment facilities at Kollsnes are designed to accommodate additional expansion.

Troll Phase II: Development of oil reserves in the Troll Vest oil province and Troll Vest gas province

Production of oil from the Troll Vest oil province

The oil province comprises the westernmost part of the field, which has a 22/26 meter oil column under a small gas cap. Production started in September 1995. By the end of 1999, 18 horizontal production wells and one gas injector had been drilled. During the past year, production has proceeded approximately as expected. Anticipated oil reserves have been increased slightly due to an overall positive reservoir development and a longer production history.

The production strategy depends on conditions such as pressure development and communication with other areas of the field. In the southern part of the oil province, as much gas as possible is reinjected, while the strategy is a controlled production of free gas together with the oil in the northern part of the province. The wells in the oil province are divided among four subsea installations that are tied into Troll B.

Production of oil from the Troll Vest gas province

The gas province comprises the middle portion of the field with an oil column of 11.5-14.5 meters and a gas column of up to 200 meters. Production of the oil reserves in the gas province may be time-critical in relation to the production of gas from both Troll Øst and Troll Vest. The stage-by-stage development has been important with regard to acquiring production experience from parts of the area before deciding on new development solutions.

The plans for development and operation of the first two subsea installations in the southern part of the Troll Vest gas province were approved by the authorities in May 1994 and July 1996 respectively. The first well group started producing in November 1995 and the second group in April 1998. Production development has been somewhat less favorable than expected after a gas breakthrough. Overall, the production rate is lower than predicted, which is mainly due to delayed progress in drilling.

A continued plan for development and operation of the oil in Troll Vest gas province was approved by the authorities in June 1997. The development plan includes nine well groups with a total of 50 horizontal production wells, whereof several multi-branched wells. Three well groups with 18 wells in the southern part of the gas province will be connected to Troll B. At the end of 1999, 12 of these wells were producing. Six well groups with 32 wells in the northern part of the province will be connected to Troll C. At the end of 1999, eight of these wells were producing. New field data and updated studies have shown that it would be profitable to increase the number of wells and subsea templates. In 1998, a supplement to the PDO was submitted,

Figure 1.10.20
Fields and discoveries in the Troll, Fram and Gjøa area

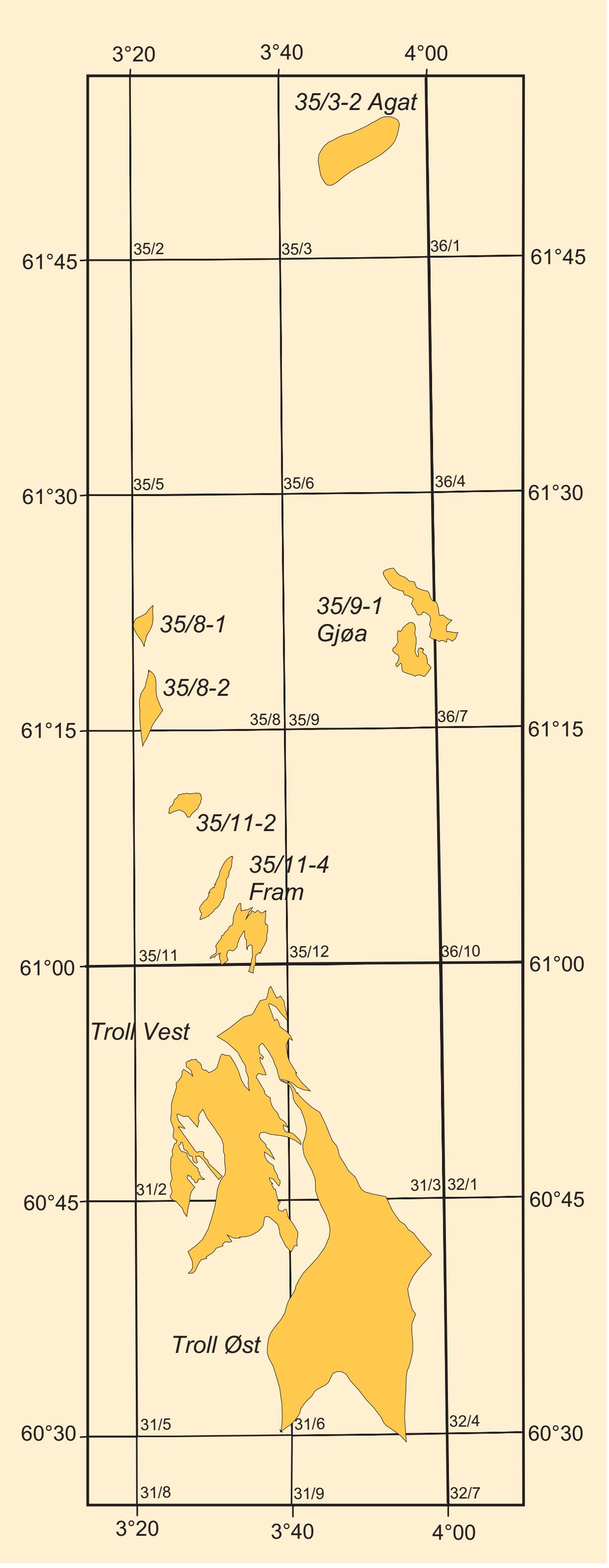
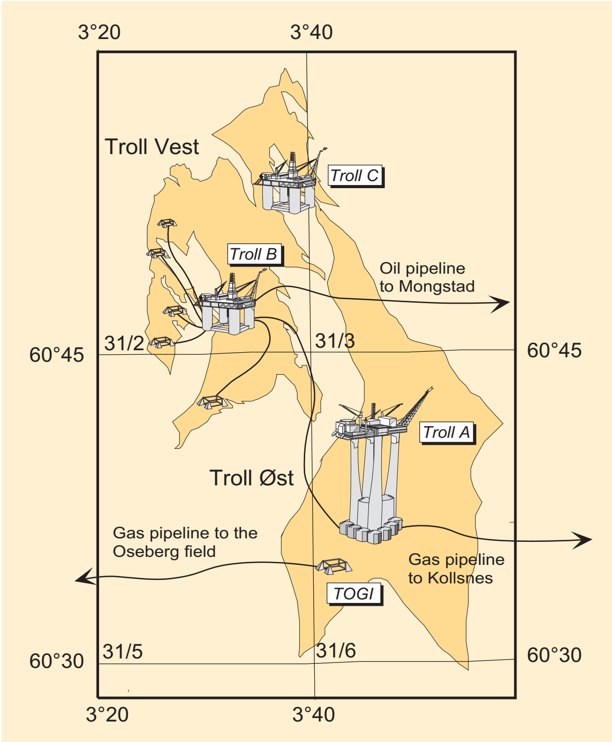


Figure 1.10.21
The Troll field



which covers the installation of an additional well group. This well group will be tied to Troll C. During the course of 1997 and 1998, several observation wells have been drilled to inter alia obtain more information regarding communication between the provinces and to see how time-critical the resources are. Super-critical production, where some production of free gas is allowed together with the oil, has been the presumed production strategy in this area.

Development

The oil reserves in the Troll Vest oil province and the southern part of the Troll Vest gas province are produced via Troll B, a floating concrete installation without storage capacity. A total of eight well clusters in the Troll Vest gas province are connected to Troll B. Troll B's production capacity is 42,500 Sm^3 oil per day. The oil is transported through Troll Oljerør (Troll oil pipeline) approx. 90 km to Mongstad. Gas which is produced together with the oil is transported via Troll A to Kollsnes for treatment and further export to the market, see Figure 1.10.21.

At least seven well groups in the northern part of the gas province will be connected to Troll C, which is a semi-submersible steel installation. The installation started operating 1 November 1999 and has an oil treatment capacity of 20,000 Sm^3 per day. A new oil pipeline is now in place from Troll C to Mongstad. A gas pipeline has also been laid to Troll A in order to utilize existing transportation opportunities to Kollsnes and on to the export market.

Troll Phase III: Development of gas resources in the Troll Vest gas province

Production

The Troll Vest gas province has a gas column of up to 200 meters over the oil zone. Approved and future recovery of the oil resources are regarded as being time-critical in relation to production of gas from Troll. Therefore, it is uncertain when major gas withdrawals from Troll Vest should start. Consideration for optimal recovery of oil and gas, the Troll field's total commitments and physical delivery capability for gas, seen in context with gas supply solutions for the Norwegian shelf, will be included in the evaluation of the timing for development of Troll Phase III.

GULLFAKS AREA

The installations on Gullfaks, see Figure 1.10.22, are an important part of the infrastructure in the Tampen area (Figure 1.10.23). In addition to treating the oil from Gullfaks and Gullfaks Vest, the installations are used for production from Tordis, Tordis Øst, Borg, Vigdis, Visund, Rimfaks, Gullfaks Sør and Gullveig.

1994 saw the beginning of deliveries from Tordis to Gullfaks C where the oil is processed. Starting in 1998, Tordis Øst and Borg have also delivered oil to Gullfaks C. From 1997, processed oil from Vigdis is routed in a pipeline via Snorre to Gullfaks A for storage and tanker shipment. The production from Visund started in 1999 and processed oil is routed in a pipeline to Gullfaks A for storage and shipment.

Oil production (Phase I) from Gullfaks Sør, Rimfaks and Gullveig started in 1998 and 1999 and is tied in to the Gullfaks A installation. Gullfaks Sør Brent Phase II, which comprises production of gas and associated liquid, will be tied in to Gullfaks C.

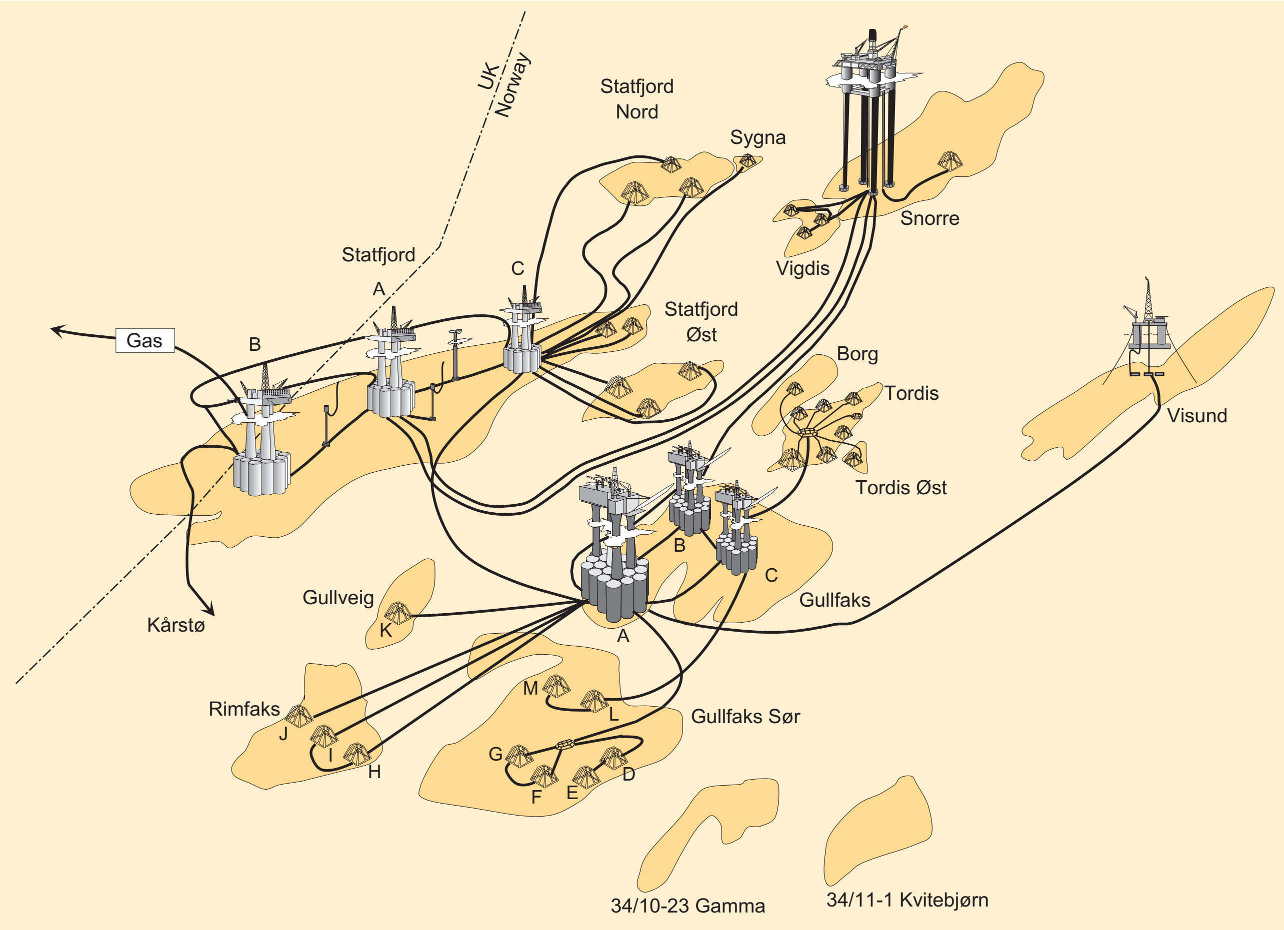
Other discoveries in the Tampen area may also be relevant for development tied in to the Gullfaks installations, but the gas treatment capacity on Gullfaks A and C will be a future constraint.

GULLFAKS

Production licence:	050	**Block:**	34/10
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 73.000 %)			91.00000 %*
Norsk Hydro Produksjon AS			9.00000 %
Discovery well:	34/10-1	Year:	1978
Development approved:	1981	Prod.start:	1986
	1985		
	1995		
Recoverable reserves:		314.8	mill. Sm^3 oil
		21.2	bill. Sm^3 gas
		2.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		76.1 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		2.3 mill.	

[1] Includes Gullfaks Vest
* Subject to approval by the Ministry of Finance

Figure 1.10.22
Infrastructure in the Tampen area



Production

Production from Gullfaks is in the decline phase and more than 80 percent of the reserves have been produced. The reservoir lies relatively shallow at a depth of 1800 - 2200 meters and is made up of several angled fault blocks with sandstone of Jurassic and Triassic Age. The blocks have variable slope degrees and parts of the area are heavily eroded. The field is also divided into two by a major north/south fault. Faults with more than a 1000-meter skip distance delimit Gullfaks to the south, east and northeast.

The field is complicated to produce due to the many faults. Initially, production started from the Brent reservoir west of the main fault and subsequently from the Brent and Statfjord reservoirs to the east. In recent years, production has also started from the Cook formation. There is also production from the Lunde formation in a small area all the way to the east on Gullfaks. The drive mechanism on the field is primarily pressure maintenance by means of water injection, but some fault segments that are too small to make pressure maintenance profitable, are produced using depressurization or natural water drive.

A total of approx. 115 wells are in operation on Gullfaks, of which 30 are gas or water injectors. Drilling of multi-branched wells and long-range wells are important methods for recovery of the remaining reserves on the field. Several wells are drilled using multiple well targets, requiring advanced techniques for completion, monitoring and operations. Remote-controlled completion, SCRAMS, has been installed in one well with good results, and well tractors are often used for operations in horizontal wells.

The recovery rate on Gullfaks is expected to reach 55 per cent based on current plans. In addition, a two-year project, Gullfaks Oil Drainage (GOD), has proven a considerable potential for increased production from Gullfaks, inter alia by locating and draining remaining oil in water-flooded areas.

Based on the basis reserves for the entire Gullfaks area, Gullfaks will be in operation up to 2016. In the final stages, the utilization of the installations will depend on discoveries in prospects and third-party use of the facilities.

Development

The Gullfaks installations are the Condeep type concrete gravity base structures with steel frame topside. The C installation is basically built as a copy of Gullfaks A. All three are fully-integrated process, drilling and living quarters installations, while Gullfaks B has a simplified process facility with only first stage separation.

Gullfaks A, which is situated on the southwestern part of the field, started production in December 1986. Treatment capacity for oil is 60,000 Sm^3 per day, while capacity for water is 38,000 m^3 per day. Gullfaks A is equipped for gas injection with a capacity of 4.0 million Sm^3 per day. In addition, a separate compressor has been installed for gas injection in Gullfaks Sør and Rimfaks with a capacity of 12.0 million Sm^3 per day. The gas treatment capacity has also been increased to 17.5 million Sm^3 per day in order to receive and treat the gas volumes from Gullfaks satellite fields. In 1999, modification work started on Gullfaks A in order to be able to export larger gas volumes when Gullfaks Sør Phase II starts producing in the autumn of 2001.

Gullfaks B is situated on the northwestern part of the field and was put into production in February 1988. It has a first stage liquid capacity of 60,000 Sm^3 per day and a water treatment capacity of 35,000 m^3 per day. The oil from Gullfaks B is transferred to Gullfaks A and Gullfaks C for further processing and storage.

Gullfaks C is located on the eastern part of the field and production started at the turn of 1989/1990. The process capacity of the installation is 56,000 Sm^3 oil and 61,000 m^3 produced water per day. Up to 78,000 m^3 water can be injected per day. In 1995, a compressor was installed for injection of gas on Gullfaks C with a capacity of 3.2 million Sm^3 per day. In 1999, modification work started on Gullfaks C in order to be able to receive gas from Gullfaks Sør Phase II starting in the autumn of 2001. The gas treatment capacity will be increased to 16 million Sm^3 per day. A new gas pipeline is being laid from Gullfaks A and C to Statpipe, which will be able to transport 26 million Sm^3 gas per day.

GULLFAKS VEST

Production licence:	050, 050 B	**Block:**	34/10
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 73.000 %)			91.00000 %*
Norsk Hydro Produksjon AS			9.00000 %
Discovery well:	34/10-34	ear:	1991
Development approved:	1993	rod.start:	1994
Recoverable reserves:		3.6	mill. Sm^3 oil
		0.4	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		0.2 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		0 mill.[1]	

[1] Part of Gullfaks
* Subject to approval by the Ministry of Finance

Gullfaks Vest started producing in 1994 with a production well tied in to Gullfaks B. Production is based on natural water drive.

GULLFAKS SØR

Production licence:	050	**Block:**	34/10
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 73.000 %)			91.00000 %*
Norsk Hydro Produksjon AS			9.00000 %
Discovery well:	34/10-2	Year:	1978
Development approved:	1996	Prod.start:	1999
	1998		
Recoverable reserves:		32.8	mill. Sm^3 oil
		61.2	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		12.0 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		48 mill.	

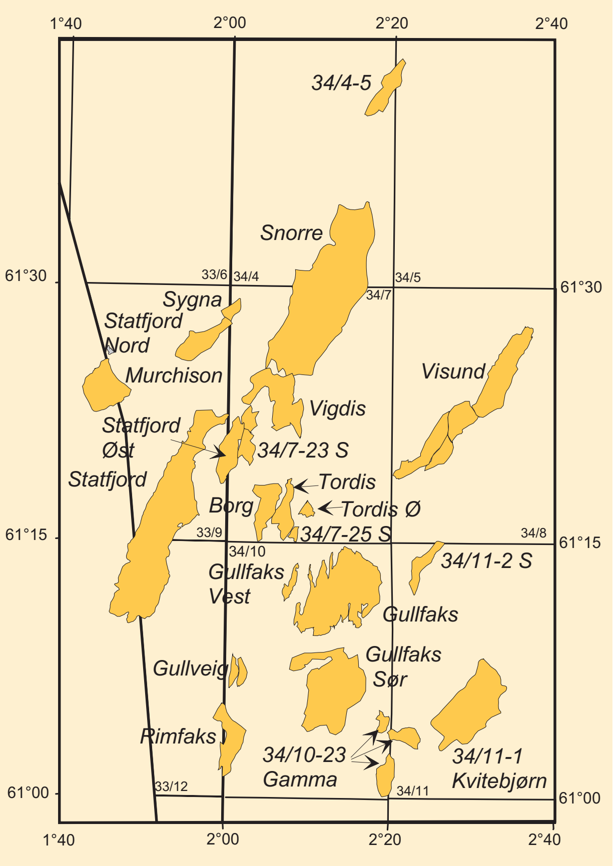
* Subject to approval by the Ministry of Finance

Production

Gullfaks Sør lies about nine km to the south of Gullfaks, see Figure 1.10.23. The reservoirs are located at a depth of 3000 - 3500 meters and contain oil and gas in sandstone of Jurassic and Triassic Ages. The structure is eroded and riddled with faults, many of which are completely or partially sealed. Several independent gas/oil and oil/water contacts have been observed in the various fault segments. The Brent reservoir contains oil and a gas cap with a high condensate content, while the Statfjord reservoir has a thicker oil zone and a smaller gas cap. There is also oil and gas in the Lunde formation.

Gullfaks Sør Phase I comprises production of oil and condensate from the Brent group and the Statfjord formation. Production started from the Brent group in March 1999 and from the Statfjord formation in April 1999. The drive mechanism is basically depressurization, but with some pressure maintenance based on reinjection of produced gas. The production properties of the Statfjord reservoir have proven poorer than expected.

Figure 1.10.23
Fields and discoveries in the Tampen area



Gullfaks Sør Phase II comprises deliveries of gas and associated liquid from the Brent reservoir. Start-up of gas deliveries is set to 1 October 2001.

Development

The plan for development and operation of Gullfaks Sør Phase I was approved in 1996 together with Rimfaks and Gullveig. The development solution comprises a total of four subsea templates with 12 wells, of which one is a subsea template for gas injection. The well stream is processed on Gullfaks A and produced gas reinjected in Gullfaks Sør and Rimfaks.

The plan for development and operation of Gullfaks Sør Phase II was approved in 1998. Phase II comprises two new subsea templates with nine new wells to the Brent reservoir as well as a new export pipeline. The well stream will be processed on Gullfaks C. Planned production start-up is the year 2001.

RIMFAKS

Production licence:	037 B, 050	**Block:**	33/12, 34/10
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 73.000 %)			91.00000 %*
Norsk Hydro Produksjon AS			9.00000 %
Discovery well:	34/10-17	Year:	1983
Development approved:	1996	Prod.start:	1999
	1998		
Recoverable reserves:		19.6	mill. Sm^3 oil
		0.0	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		5.4 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		48 mill.	

* Subject to approval by the Ministry of Finance

Production

Rimfaks, which lies approx. 15 kilometers southwest of Gullfaks with reservoirs at a depth of 2500 - 3000 meters, see Figure 1.10.23, contains oil and gas with a high condensate content in the Brent group and Statfjord formation from the Jurassic Age. As is the case for Gullfaks Sør, Rimfaks has a complex geology with many fault blocks. Production started from the Statfjord formation in February 1999 and gas injection in July 1999. Gas from Rimfaks and Gullfaks Sør is reinjected in order to produce the field using pressure maintenance.

Development

The plan for development and operation was approved in 1996 together with Gullfaks Sør and Gullveig.

The development concept includes three subsea templates, of which one is for gas injection, with a total of 10 wells. The well stream is processed on the Gullfaks A installation.

GULLVEIG

Production licence:	050	**Block:**	34/10
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 73.000 %)			91.00000 %*
Norsk Hydro Produksjon AS			9.00000 %
Discovery well:	34/10-37	ear:	1995
Development approved:	1996	rod.start:	1998
Recoverable reserves:		2.7	mill. Sm^3 oil
		2.0	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		0.9 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		6 mill.	

* Subject to approval by the Ministry of Finance

Production

Gullveig contains oil in sandstone from the Brent group of the Jurassic Age, see Figure 1.10.23. The reservoir lies at a depth of 2500 - 3000 meters and consists of a single inclined fault block. Resources have also been proven in the Statfjord formation. The field started production in the autumn of 1998 and is produced using depressurization and natural water drive.

Development

The plan for development and operation was approved in 1996 together with Gullfaks Sør and Rimfaks. The development concept comprises a subsea template with two wells that are connected to the Gullfaks A installation.

STATFJORD AREA

STATFJORD

Business area:	Statfjord Unit		
Production licence:	037	**Block:**	
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Norwegian part (85.46869%)			
A/S Norske Shell			8.54687 %
Den norske stats oljeselskap a.s			44.33688 %*
Enterprise Oil Norwegian AS			0.89030 %
Esso Expl. and Prod. Norway A/S			8.54687 %
Mobil Development Norway AS			12.82030 %
Norske Conoco A/S			10.32747 %
British part (14.53131%)			
BP Amoco			4.84377 %
Conoco (UK) LTD			4.84377 %
Chevron UK Ltd.			4.84377 %
Discovery well:	33/12-1	ear:	1974
Development approved:	1976	rod.start:	1979
	1981		
Recoverable reserves:		569.5	mill. Sm^3 oil
		56.4	bill. Sm^3 gas
		13.9	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		97.9 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		2.3 mill.	

[1)]Norwegian share (85.46869 %)
* Subject to approval by the Ministry of Finance

Production

The Statfjord field, see Figure 1.10.23, consists of a large fault block sloping to the west, as well as a number of smaller fault blocks along the east flank. The field extends into the British continental shelf. The reservoirs on the Statfjord field consist of sandstone from the Brent group, the Cook formation and the Statfjord formation.

Up to just a few years ago, the Brent reservoir was produced with the aid of pressure support from water injection. Based on the results of a project with WAG injection in lower Brent and reservoir studies conducted, it was decided in 1998 that WAG injection would be implemented as the production strategy in Brent. Calculations indicate that WAG injection in Brent provides increased oil recovery in the order of 12 - 13 million Sm^3.

The Statfjord formation has been produced with the aid of pressure support from gas injection. A new production strategy for the Statfjord formation, with upflank water injection and supplementary gas injection in upper Statfjord and downflank WAG injection in lower Statfjord, will be gradually implemented based on production experience and reservoir studies.

The Cook reservoir came on stream in 1994. The production strategy for the Cook formation is based on phasing in wells which have already penetrated the reservoir, and possibly deepening of existing wells. Production will receive pressure support from water injection. The production strategy also entails well workovers and side drilling of existing wells that are flooded with water. Use of horizontal wells and long-range, high-deviation wells is included in the strategy.

The field's north flank was put into production in August 1999. Well results and production development in this area have proven poorer than expected. This has entailed a downward adjustment of the north flank reserves estimate.

Development

The field has been developed in three phases with the fully integrated installations A, B and C, see Figure 1.10.22. Statfjord A is situated close to the center of the Statfjord field and started producing in November 1979. The processing capacity for oil on Statfjord A is roughly 67,000 Sm^3 per day and the installation has a storage capacity of 175,000 Sm^3. The capacity for water injection is approximately 69,000 m^3 per day. From August 1992, partially processed oil from Snorre TLP was phased in to Statfjord A. This has enabled good utilization of Statfjord A's available processing capacity.

Statfjord B is situated on the southern part of the Statfjord field and started producing in November 1982. The production capacity for oil is roughly 40,000 Sm^3 per day and the installation has a storage capacity of 302,000 Sm^3. The capacity for water injection is approximately 64,000 m^3 per day.

Statfjord C is situated on the northern part of the Statfjord field and started producing in June 1985. The installation is structurally identical to Statfjord B. The production capacity for oil is roughly 52,000 Sm^3. The capacity for water injection on Statfjord C is about 62,000 m^3 per day. The Statfjord satellite fields have their own intake separator on Statfjord C with a capacity of roughly 25,000 Sm^3 oil.

Stabilized oil is stored in storage cells on each installation. Loading of oil takes place via one of the three oil loading systems on the field. Gas is transported through the Statpipe pipeline and sold in Emden, while NGL is removed at Kårstø. The United Kingdom takes its share of the gas through NLGP (Northern Leg Gas Pipeline) from Statfjord B to St. Fergus in Scotland.

Oil and gas are metered to fiscal standard on each of the three installations. After Snorre started production, Statfjord A production is determined as the difference between the total volume metered on Statfjord A and the volume metered on Snorre. A similar concept is used for determination of Statfjord C production after the Statfjord satellite fields began producing. The distribution between the satellite fields will be based on test separator metering, while the total volume from the satellite fields will be metered to fiscal standard.

The north flank of the Statfjord field has been developed with two subsea installations; one for production and one for injection, tied to Statfjord C. The production from the north flank started in the summer of 1999. During 2000, the Sygna field will also be phased in to Statfjord C for processing, stabilization, storage and export of the oil.

STATFJORD ØST

Business area:	Statfjord Øst Unit		
Production licence:	037, 089	**Block:**	33/9, 34/7
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
A/S Norske Shell			5.00000 %
Den norske stats oljeselskap a.s (SDFI 40.500 %)			55.04750 %*
Elf Petroleum Norge AS			2.80000 %
Enterprise Oil Norwegian AS			0.52060 %
Esso Expl. and Prod. Norway A/S			10.25000 %
Idemitsu Petroleum Norge AS			4.80000 %
Mobil Development Norway AS			7.50000 %
Norsk Hydro Produksjon AS			4.20000 %
Norske Conoco A/S			6.04140 %
RWE-DEA Norge AS			1.40000 %
Saga Petroleum ASA			2.44050 %
Discovery well:	33/9-7	Year:	1976
Development approved:	1990	Prod.start:	1994
Recoverable reserves:		35.7	mill. Sm^3 oil
		5.1	bill. Sm^3 gas
		1.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		4.9 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		37 mill.	

* Subject to approval by the Ministry of Finance

Production

The reservoir on the Statfjord Øst field consists of sandstone from the Middle Jurassic Age in the upper and lower part of the Brent group. The field is produced using pressure maintenance from water injection. The final planned production well was drilled and put into production in 1999.

The field is currently produced by means of a total of seven production wells and three injection wells. There is continuous evaluation of the need for well workovers and side drilling of existing wells on the field.

Statfjord Øst has two available slots, one for production and one for injection, that may be used to produce other deposits in the vicinity of the field.

Development

The field was developed with subsea installations connected to the Statfjord C installation. The subsea installations consist of three templates, of which two are for production and one for water injection, see Figure 1.10.22. Each template has four well slots. The well stream is transferred via two pipelines to Statfjord C for processing, storage and further transport. Statfjord Øst and Statfjord Nord utilize common processing facilities on Statfjord C. The capacity for water injection is approximately 18,000 m^3 per day.

The Statfjord satellite fields are metered to fiscal standard in a common metering system on Statfjord C. Return allocation to the individual satellite field is done on the basis of test separator metering.

STATFJORD NORD

Production licence: 037		**Block:**	33/9
Operator: Den norske stats oljeselskap a.s			
Licensees:			
A/S Norske Shell			10.00000 %
Den norske stats oljeselskap a.s (SDFI 30.000 %)			51.87500 %*
Enterprise Oil Norwegian AS			1.04167 %
Esso Expl. and Prod. Norway A/S			10.00000 %
Mobil Development Norway AS			15.00000 %
Norske Conoco A/S			12.08333 %
Discovery well:	33/9-8	Year:	1977
Development approved:	1990	Prod.start:	1995
Recoverable reserves:		41.6	mill. Sm^3 oil
		3.1	bill. Sm^3 gas
		0.7	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		5.9 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		185 mill.	

* Subject to approval by the Ministry of Finance

Production

The reservoir on Statfjord Nord consists of sandstone belonging to the Brent group (Middle Jurassic) and sandstone of the Late Jurassic Age (the Munin formation). The field is produced using pressure maintenance from water injection. The two final planned wells, one production well and one injection well, were drilled during the course of 1999. Eight production wells and three injection wells have now been completed. There is a continuous evaluation of the need for well workovers and side drilling of existing wells on the field.

Development

The field was developed with subsea installations connected to the Statfjord C installation. The subsea installations consist of three templates, of which two are for production and one for water injection, see Figure 1.10.22. Each template has four well slots. The well stream is transferred via two pipelines to Statfjord C for processing, storage and further transport. Statfjord Nord and Statfjord Øst use common facilities on Statfjord C.

The last available well slot on the Statfjord Nord injection template will be used for an injection well on the Sygna field. During the course of 1999, an upgrading of the water injection capacity to the Statfjord Nord area was implemented in the amount of 12,500 m^3 per day, so that the Statfjord Nord and Sygna injection capacity totals 28,000 m^3 per day.

The Statfjord satellite fields are metered to fiscal standard in a common metering system on Statfjord C. Return allocation to the individual satellite field is done on the basis of test separator metering.

Production from the Statfjord satellite fields contributes to good exploitation of the process facilities on Statfjord C.

SYGNA

Business area:	Sygna Unit		
Production licence:	037, 089	**Block:**	33/9, 34/7
Operator: Den norske stats oljeselskap a.s			
Licensees:			
A/S Norske Shell			5.50000 %
Den norske stats oljeselskap a.s (SDFI 39.450 %)			54.73000 %*
Elf Petroleum Norge AS			2.52000 %
Enterprise Oil Norwegian AS			0.57290 %
Esso Expl. and Prod. Norway A/S			10.22500 %
Idemitsu Petroleum Norge AS			4.32000 %
Mobil Development Norway AS			8.25000 %
Norsk Hydro Produksjon AS			3.78000 %
Norske Conoco A/S			6.64580 %
RWE-DEA Norge AS			1.26000 %
Saga Petroleum ASA			2.19630 %
Discovery well:	33/9-19 S	ear:	1996
Development approved:	1999	rod.start:	2000
Recoverable reserves:		9.3	mill. Sm^3 oil
		0.6	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		1.6 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		45 mill.	

* Subject to approval by the Ministry of Finance

Production

The reservoir on Sygna consists of sandstone belonging to the Brent group of Middle Jurassic Age, see Figure 1.10.23. The plan is to produce the field with two production wells and pressure maintenance from one water injection well. All three wells are scheduled for drilling during 2000. Production start-up is planned for August 2000.

Development

The field will be developed with a four-well subsea template for production and the well stream is transported to Gullfaks C for processing, stabilization, storage and shipping. The injection well will be drilled from the existing injection template on Statfjord Nord. During the course of 1999, an upgrading of the water injection capacity in the Statfjord Nord area was implemented in order to supply injection water to Sygna. The total Statfjord Nord and Sygna injection capacity is now 28,000 m^3 per day.

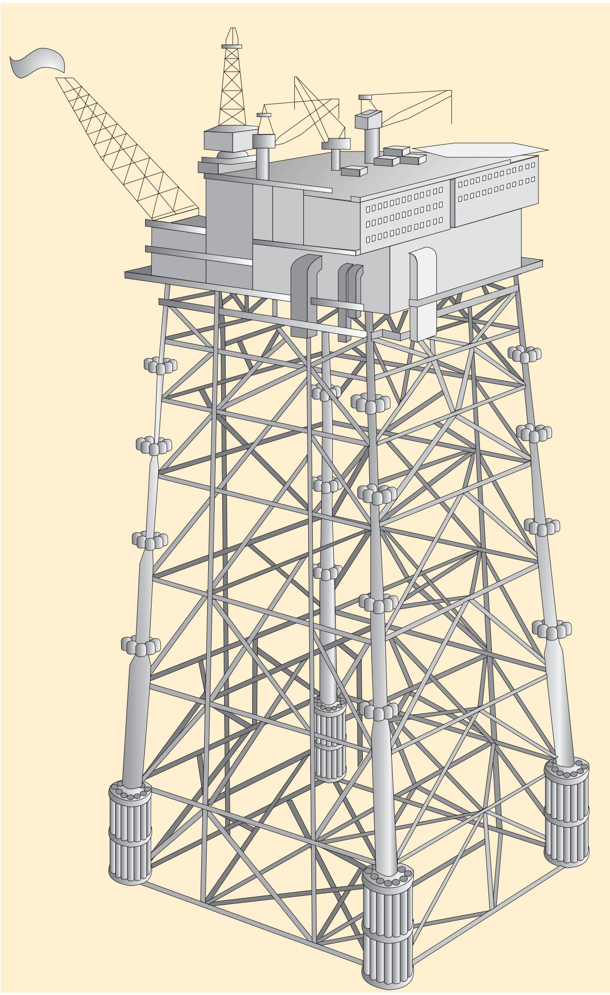
MURCHISON

Business area:	Murchison Unit			
Production licence:	037	**Block:**	33/9	
Operator:	Oryx (UK) Energy Company			
Licensees:				
A/S Norske Shell			2.22000 %	
Den norske stats oljeselskap a.s			11.51620 %*	
Enterprise Oil Norwegian AS			0.23120 %	
Esso Expl. and Prod. Norway A/S			2.22000 %	
Mobil Development Norway AS			3.33000 %	
Norske Conoco A/S			2.68260 %	
Oryx (UK) Energy Company			68.72334 %	
Ranger Oil (UK) Ltd			9.07666 %	
Discovery well:	33/9-4	ear:	1975	
Development approved:	1976	rod.start:	1980	
Recoverable reserves:[1]		13.6	mill. Sm^3 oil	
		0.4	bill. Sm^3 gas	
		0.4	mill. tonnes NGL	
		0.0	mill. Sm^3 cond.	
Total investments (firm 1999-NOK):		6.2 bill.		
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		77 mill.		

[1] Norwegian share (22.2 %)

* Subject to approval by the Ministry of Finance

Figure 1.10.24
Installation on Murchison



Production

The Murchison reservoir, see Figure 1.10.23, consists of sandstone belonging to the Brent group. The field has produced at nearly maximum liquid processing capacity since 1981, and water treatment capacity has been increased several times. Most of the production wells are now producing with a high water cut. In order to increase oil production and extend field lifetime, the operator has planned for an active well strategy. Ruined wells are repaired and wells flooded with water are side drilled to undrained areas and prospects around the field. Murchison is expected to produce until around 2005/2006.

Development

The field has been developed with an integrated steel installation with a production capacity of 26,200 Sm^3 oil per day, see Figure 1.10.24.

Oil from Murchison is sent via pipeline to Sullom Voe on Shetland. The Norwegian share of the Murchison gas is landed via the NLGP pipeline (Northern Leg Gas Pipeline) to the Brent field on the British side, and on to St. Fergus, Scotland in the FLAGS pipeline (Far North Liquified and Associated Gas Gathering System).

SNORRE

Business area:	Snorre Unit			
Production licence:	057, 089	**Block:**	34/4, 34/7	
Operator:	Saga Petroleum ASA			
Licensees:				
Amerada Hess Norge AS			1.18060 %	
Den norske stats oljeselskap a.s (SDFI 31.400 %)			44.40000 %*	
Elf Petroleum Norge AS			5.95100 %	
Enterprise Oil Norwegian AS			1.18060 %	
Esso Expl. and Prod. Norway A/S			11.15810 %	
Idemitsu Petroleum Norge AS			9.60000 %	
Norsk Hydro Produksjon AS			8.92650 %	
RWE-DEA Norge AS			8.87870 %	
Saga Petroleum ASA			8.72450 %	
Discovery well:	34/4-1	Year:	1979	
Development approved:	1988	Prod.start:	1992	
	1994			
	1998			
Recoverable reserves:		225.3	mill. Sm^3 oil	
		9.2	bill. Sm^3 gas	
		6.0	mill. tonnes NGL	
		0.0	mill. Sm^3 cond.	
Total investments (firm 1999-NOK):		53.8 bill.		
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		1.1 mill.		

* Subject to approval by the Ministry of Finance

Production

The Snorre field, see Figure 1.10.23, consists of several larger fault blocks. The reservoir rocks are fluvial sandstone in the Statfjord and Lunde formations of the Early Jurassic and Triassic Ages. The reservoir intervals vary from broad, continuous channel belts where reservoir communication is good, to narrower, isolated channel belts where the communication conditions are poorer.

Originally, the plan was to produce the field with pressure maintenance using water injection. Based on comprehensive studies and a pilot project in 1994 with WAG

Resource management

injection, a decision was made to change the production strategy from water injection to downflank WAG injection in the Statfjord formation. Further optimization has also led to implementation of upflank WAG injection in the Statfjord and Lunde formations in the eastern part of the field. Use of horizontal and high-deviation wells is also included in the strategy.

In connection with preparation of a plan for development and operation (PDO) for the northern areas of the field (Snorre Phase 2) in 1998, a decision was made to implement WAG injection as a production strategy for the entire field. The decision is based on comprehensive reservoir studies and experience gained from WAG injection in the southern areas.

Development

Phase 1

The Snorre field will be developed in two phases. Phase I consists of a floating tension leg platform in the south (Snorre TLP), and a subsea template with 10 slots (Snorre SPS) connected to Snorre TLP in the central part of the field, see Figure 1.10.22. Snorre TLP started producing in August 1992.

Oil and gas are separated in two stages on Snorre TLP, metered to fiscal standard and then transported in separate oil and gas pipelines to Statfjord A for final processing. The oil is then exported via the loading system on Statfjord A and the gas is transported in the Statpipe system. After the field started operations, the oil processing and gas injection capacities have been increased to 39,000 Sm^3 and five million Sm^3 per day respectively. This upgrade was completed in 1997.

In connection with the development of the Vigdis field in 1996, a new process module was installed on Snorre TLP. The module contains a three-stage separation train for full stabilization of oil from Vigdis and is designed for an oil capacity of 18,000 Sm^3 per day. Oil from Vigdis is metered to fiscal standard and sent via a separate pipeline to Gullfaks A for storage and shipping.

A crossover pipeline has been laid between the Snorre and Vigdis process lines so that produced oil volumes from Vigdis can be transported both to Gullfaks and to Statfjord.

Phase 2

Phase 2 of the Snorre development (Snorre B) comprises production from the northern part of the field. The plan for development and operation of Snorre Phase 2 was approved by the authorities in July 1998. The operator's plan is based on development with a semi-submersible steel production installation with drilling and injection facilities. The oil will be transferred to Statfjord B for storage and loading, while the gas will be reinjected in order to increase oil production.

On Snorre B, the oil processing capacity in first and second stage separation is designed for 18,000 Sm^3 per day. A capacity of 30,000 Sm^3 is planned for the third stage of separation, and this will provide for potential subsequent tie-in and final processing of partially stabilized oil from Snorre TLP. The capacity for processing and injection of gas is designed for three million Sm^3 per day. Provisions will be made for a potential subsequent upgrade of the gas capacity to five million Sm^3 per day. Production start-up for Snorre B is planned for August 2001.

VIGDIS

Production licence:	089	**Block:**	34/7
Operator:	Saga Petroleum ASA		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 51.000 %)			58.22000 %*
Elf Petroleum Norge AS			5.60000 %
Esso Expl. and Prod. Norway A/S			10.50000 %
Idemitsu Petroleum Norge AS			9.60000 %
Norsk Hydro Produksjon AS			8.40000 %
RWE-DEA Norge AS			2.80000 %
Saga Petroleum ASA			4.88000 %
Discovery well:	34/7-8	ear:	1986
Development approved:	1994	rod.start:	1997
Recoverable reserves:		33.3	mill. Sm^3 oil
		2.3	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		6.0 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		93 mill.	

* Subject to approval by the Ministry of Finance

Production

The field, see Figure 1.10.23, consists of one western, one middle and one eastern main segment. The reservoir in the western and middle segment, which has been approved for development, consists of sandstone in the upper and lower part of the Brent group from the Middle Jurassic Age. In the eastern segment (Vigdis Øst), oil has been proven in Upper Jurassic sand and in the Statfjord formation. Development of the resources in this segment will be viewed in context with other discoveries and prospects in the Vigdis area.

The field is produced using pressure maintenance from water injection. Primarily, eight production wells and four injection wells are planned. In order to increase recovery from the main field, up to three additional production wells are being considered for segments not covered by primary drilling. These are planned as side drilling from existing production wells being flooded with water.

There is also a potential for additional resources in the surrounding structures. Phase-in of potential additional resources can take place through drilling of wells from new templates connected to existing installations, or by using slots which are freed when other wells are phased out due to high water production.

Development

The field, see Figure 1.10.22, is developed with subsea installations tied in to Snorre TLP. The subsea installations consist of three subsea templates, of which two are for production and one for water injection. Each subsea template contains four well slots. The well stream is transferred to Snorre TLP for processing and metering. The process module for Vigdis on Snorre TLP is designed for an oil and liquid capacity of 18,000 and 20,000 Sm^3 per day respectively. The stabilized oil is sent via a separate pipeline to Gullfaks A for storage and shipping. Gas produced from Vigdis is injected on the Snorre field and contributes to increased oil recovery on Snorre.

Snorre TLP will also deliver injection water to Vigdis. The design capacity for water injection is 22,000 m^3 per day.

There are several discoveries and prospects in the Vigdis area that are being considered for phase-in towards the Vigdis installations. Plans for future development of the Vigdis area will be considered during the course of 2000.

TORDIS

Production licence:	089	Block:	34/7
Operator: Saga Petroleum ASA			
Licensees:			
Den norske stats oljeselskap a.s (SDFI 51.000 %)			58.22000 %*
Elf Petroleum Norge AS			5.60000 %
Esso Expl. and Prod. Norway A/S			10.50000 %
Idemitsu Petroleum Norge AS			9.60000 %
Norsk Hydro Produksjon AS			8.40000 %
RWE-DEA Norge AS			2.80000 %
Saga Petroleum ASA			4.88000 %
Discovery well:	34/7-12	ear:	1987
Development approved:	1991	rod.start:	1994
Recoverable reserves:		29.9	mill. Sm^3 oil
		3.1	bill. Sm^3 gas
		0.7	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		5.3 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		112 mill.	

* Subject to approval by the Ministry of Finance

Production

The reservoir on the Tordis field consists of sandstone in the upper and lower part of the Brent group from the Middle Jurassic Age. Faults divide the field into three main segments, one southern, one western and one eastern segment. Production experience shows good communication between the different segments on the field.

The plan is to produce the field, see Figure 1.10.23, with pressure maintenance with the aid of water injection using five production wells and two injection wells. Drilling of the injection wells has been postponed for several years as the reservoir has had natural pressure support from the water zone. The first injection well on Tordis was drilled and injection commenced in 1999. The well proved less oil/water contact than expected in the western segment. In light of this and positive production experience from the field, the total resource estimate has been increased somewhat. The need for and when to drill the second injection well will be continuously evaluated.

Development

The field was developed with a subsea installation that is connected to the Gullfaks C installation. The subsea installation consists of a central manifold with seven satellite wells and connection points for other templates, see Figure 1.10.22.

The well stream from the Tordis area is transferred to Gullfaks C and is separated in a separate single-stage process. Processing capacity for oil and liquid from the Tordis area on Gullfaks C is 16,000 and 18,000 Sm^3 per day respectively. Oil and gas are metered prior to further treatment in the existing process facilities on Gullfaks C. The oil is exported via loading buoys to tankers and the gas is transported in the Statpipe system.

Tordis Øst was connected to the central manifold for the Tordis installation with a four-well template and commenced production in 1998. The Borg field, utilizing the Tordis Øst template, commenced regular production in 1999 after six months of test production. Thus, these two fields contribute to good exploitation of the Tordis installations and process capacity. A four-well template for injection wells was installed on the field in 1999. The plan is to use this subsea template for Tordis, Tordis Øst and Borg. The total water injection capacity for the Tordis area is 18,000 m^3 per day.

TORDIS ØST

Production licence:	089	Block:	34/7
Operator: Saga Petroleum ASA			
Licensees:			
Den norske stats oljeselskap a.s (SDFI 51.000 %)			58.22000 %*
Elf Petroleum Norge AS			5.60000 %
Esso Expl. and Prod. Norway A/S			10.50000 %
Idemitsu Petroleum Norge AS			9.60000 %
Norsk Hydro Produksjon AS			8.40000 %
RWE-DEA Norge AS			2.80000 %
Saga Petroleum ASA			4.88000 %
Discovery well:	34/7-22	Year:	1993
Development approved:	1995	Prod.start:	1998
Recoverable reserves:		5.2	mill. Sm^3 oil
		0.5	bill. Sm^3 gas
		0.1	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		0.6 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		2 mill.	

* Subject to approval by the Ministry of Finance

Production

The field, see Figure 1.10.23, consists of two segments; a northern and a southern main segment. For the most part, the reserves are found in the Tarbert formation belonging to the Brent group of the Middle Jurassic Age. Drilling of two observation wells in 1997 and a production well in 1998 have shown that the reservoir is more complex, with a more complicated fault pattern than previously assumed. However, the field has shown very good production properties during 1999.

The field is produced using one production well, with one water injection well planned. The decision regarding the need for the injection well on Tordis Øst will be made after some production experience has been gained and is dependent on the communication between the faults, as well as the amount of natural pressure support the field has from the underlying water zone.

Development

The field is developed by means of a four-well subsea template tied into the central manifold on the Tordis installations, see Figure 1.10.22. The well stream from Tordis, Tordis Øst and Borg is mixed and then transported through pipelines to the Gullfaks C installation for processing, metering, storage and shipping. The plan is that Tordis Øst will use one of the four well slots on the subsea template. The remaining three well slots will be used by Borg and, if relevant, discovery 34/7-25 S.

In the event of a need for water injection, Tordis Øst will receive injection water from Tordis. If relevant, the injection well will be drilled from the new four-well subsea template that was installed on the Tordis field in 1999. The plan is to use this subsea template for Tordis, Tordis Øst and Borg.

BORG

Production licence:	089	**Block:**	34/7
Operator:	Saga Petroleum ASA		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 51.000 %)			58.22000 %*
Elf Petroleum Norge AS			5.60000 %
Esso Expl. and Prod. Norway A/S			10.50000 %
Idemitsu Petroleum Norge AS			9.60000 %
Norsk Hydro Produksjon AS			8.40000 %
RWE-DEA Norge AS			2.80000 %
Saga Petroleum ASA			4.88000 %
Discovery well:	34/7-21	ear:	1992
Development approved:	1999	rod.start:	1999
Recoverable reserves:		12.6	mill. Sm^3 oil
		1.6	bill. Sm^3 gas
		0.4	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		0.8 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		2 mill.	

* Subject to approval by the Ministry of Finance

Production

The Borg reservoir, see Figure 1.10.23, consists of Late Jurassic sandstone. Due to the uncertainty connected with the extent of the sand and communication conditions in the reservoir, a test production from the discovery was performed in 1998 that lasted for six months. A well slot on the Tordis Øst subsea template was used for the test production. The purpose was to optimize the production strategy and the development concept. The uncertainty with regard to the reserves in place has been significantly reduced, and test production has provided valuable production experience from the Top Draupne sand.

Borg was approved for development and put into production in July 1999 by reopening an earlier test production well. The plan is to produce the field with three production wells and pressure maintenance with the aid of two water injection wells.

There are also potential additional resources in a segment north of Borg. An appraisal well in this segment is scheduled for 2001.

Development

The field will utilize the remaining well slots on the Tordis Øst subsea template tied into the central manifold on the Tordis installation, see Figure 1.10.22. The well stream from Tordis, Tordis Øst and Borg is mixed and then transported through field pipelines to the Gullfaks C installation for processing, metering, storage and shipping.

An injection well has been drilled from a satellite template on Tordis and an injection well will be drilled from the new four-well injection template that was installed on the Tordis field in 1999. The plan is to use this subsea template for Tordis, Tordis Øst and Borg.

VISUND

Business area:	Visund Unit		
Production licence:	120	**Block:**	34/8
Operator:	Norsk Hydro Produksjon AS		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 49.600 %)			62.90000 %
Elf Petroleum Norge AS			7.70000 %
Norsk Hydro Produksjon AS			16.10000 %
Norske Conoco A/S			9.10000 %
Saga Petroleum ASA			4.20000 %
Discovery well:	34/8-1	ear:	
Development approved:	1996	rod.start:	1999
Recoverable reserves:		48.5	mill. Sm^3 oil
		0.0	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		12.9 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		192 mill.	

Production

Visund lies about 22 kilometers to the northeast of Gullfaks, see Figure 1.10.23, and contains oil and gas in sandstone at a depth of 2800 - 2900 meters from the Jurassic and Triassic Ages.

The reservoir is made up of several angled fault blocks with several separate pressure and liquid systems. The field is complicated to produce due to the many, partly sealed faults. Production started from the Brent reservoir in April 1999. During production of the oil phase (Phase I), the drive mechanism will be pressure maintenance through water injection, gas injection and WAG. All produced gas will be reinjected into the reservoir until a gas sales agreement has been realized. Gas injection started in July 1999 in the Brent Sør segment. Phase I production is planned with 13 horizontal production wells and eight injection wells.

Three of the wells were predrilled before the installation was put in place. In addition, a stepped-up development of the northern part of Visund is planned with one or more horizontal wells.

Development

The plan for development and operation was approved in 1996. The development concept comprises integrated semi-submersible living quarters, drilling and process installation in steel equipped for complete stabilization of oil and injection of gas and water. The installation is designed to process up to 16,000 Sm^3 oil per day, which will be transported via a pipeline to Gullfaks A for storage and shipping, see Figure 1.10.22. The gas injection capacity is 10 million Sm^3 per day and the water injection capacity is 18,000 m^3 per day.

DISCOVERIES

1/3-3 TAMBAR

Production licence:	019 B, 065	**Block:**	1/3, 2/1
Operator:	BP Amoco Norge AS		
Discovery well:	1/3-3	Year:	1983
Earliest production start:		Year:	2001
Recoverable resources:		5.6	mill. Sm^3 oil
		1.5	bill. Sm^3 gas
		0.3	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 0.8 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 26 million	

The deposit is an oil discovery made in the Ula formation from the Late Jurassic Age, see Figure 1.10.1. BP took over Elf's interest as well as operatorship in the production license in 1997. The authorities received a draft plan for development and operations for the discovery in December 1999. The final plan is expected in January 2000.

The plan is to develop the discovery by means of a wellhead installation with two production wells tied to Ula for processing and transportation. Produced gas is considered for injection into the Ula reservoir as part of the Ula WAG injection project. New measurements performed in 1999 indicate that the formation is not very suited for water injection. Additional studies will be performed and the development concept allows for injection of water at a later stage in order to increase the reserves if possible.

2/4-17 TJALVE

Production licence:	018	**Block:**	2/4
Operator:	Phillips Petroleum Company Norway		
Discovery well:	2/4-17	Year:	1992
Earliest production start:		Year:	2007
Recoverable resources:		1.3	mill. Sm^3 oil
		1.7	bill. Sm^3 gas
		0.1	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 0.4 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 27 million	

Tjalve contains gas/condensate in a 50-meter thick sandstone reservoir of the Late Jurassic Age in the lower Ula formation. The structure is a combined fault-conditional and stratigraphic trap that lies at a depth of about 4300 meters. The drive mechanism for production will be gas expansion through depressurization. However, the discovery well has been temporarily abandoned and may be used for subsequent production.

The discovery, see Figure 1.10.1, has been evaluated for development with transportation via the Tor field to Ekofisk II, either through a seabed installation and pipeline or through a production well drilled from Tor, which lies at a distance of about 7 kilometers from the Tjalve discovery. The timing of phase-in to Ekofisk II is being evaluated.

2/12-1 FREJA

Production licence:	113	**Block:**	2/12
Operator:	Amerada Hess Norge AS		
Discovery well:	2/12-1	Year:	1987
Earliest production start:		Year:	2004
Recoverable resources:		2.0	mill. Sm^3 oil
		0.3	bill. Sm^3 gas
		0.1	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 0.6 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 26 million	

The discovery lies near the dividing line between the Norwegian and Danish shelves, see Figure 1.10.1, in a complex faulted area between Fedagraben to the west and Gertrudgraben to the east. The reservoir is in Upper Jurassic sand at a depth of about 4900 meters. Faults segment the reservoir, and the field can be divided into separate fault blocks. The reservoir is deep and the reservoir pressure is one of the highest on the Norwegian shelf.

A development using a wellhead installation with four well slots tied in to transportation solutions using existing infrastructure is assumed.

3/7-4 TRYM

Production licence:	147	**Block:**	3/7
Operator:	A/S Norske Shell		
Discovery well:	3/7-4	Year:	1990
Earliest production start:		Year:	2004
Recoverable resources:		0.0	mill. Sm^3 oil
		3.3	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.8	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 0.4 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 28 million	

The Trym and Lulita discoveries lie on the same salt-induced structure. The structure crosses the boundary between the Norwegian and Danish shelves. Trym is considered to be 100 percent Norwegian while it is assumed that Lulita extends onto the Norwegian shelf.

It is assumed that Trym is separated from Lulita, but with possible pressure communication in the water zone. The reservoirs lie in the Lindesnes and Bryne formations in the Late and Middle Jurassic Age. The Lindesnes formation is relatively homogeneous with good reservoir properties, while the Bryne formation is extremely heterogeneous with varying reservoir quality.

The Danish part of Lulita has been developed by means of tying the development to the nearby Danish field, Harald. The Danish and Norwegian owners are trying to achieve a unitization agreement for the Lulita field. It is assumed that the Trym field will be developed with the aid of a subsea concept with a two-branch well with gas export through an eight-kilometer pipeline to the Harald installation on the Danish shelf

15/5-1 DAGNY

Production licence:	029, 048	**Block:**	15/5, 15/6
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	15/5-1	Year:	1978
Earliest production start:		Year:	2002
Recoverable resources:		0.0	mill. Sm^3 oil
		5.8	bill. Sm^3 gas
		1.0	mill. tonnes NGL
		1.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 1.4 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 54 million	

This is a gas and condensate discovery in Jurassic rock to the north of Sleipner Vest, see Figure 1.10.8. The most interesting development concept is subsea wells or an unmanned wellhead installation connected to Sleipner B or Sleipner T.

16/7-4 SIGYN

Production licence:	072	**Block:**	16/7
Operator:	Esso Expl. and Prod. Norway A/S		
Discovery well:	16/7-4	Year:	1982
Earliest production start:		Year:	2002
Recoverable resources:		0.0	mill. Sm^3 oil
		5.8	bill. Sm^3 gas
		2.0	mill. tonnes NGL
		4.7	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 2.4 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 84 million	

This discovery lies about 12 kilometers southeast of Sleipner A. The discovery, see Figure 1.10.9, was made in the Skagerrak formation and contains gas/condensate. Development of the discovery as a satellite to Sleipner A is in progress. The gas may be used for injection in Sleipner Øst. Both subsea-completed wells and a wellhead installation are being evaluated.

25/4-6 S VALE

Production licence:	036	**Block:**	25/4
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	25/4-6 S	Year:	1991
Earliest production start:		Year:	2001
Recoverable resources:		0.0	mill. Sm^3 oil
		3.0	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		3.5	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 0.8 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 70 million	

Gas/condensate has been proven in reservoirs from the Brent group of the Middle Jurassic Age. The drive mechanism is depressurization. The plan is to develop the discovery with a subsea installation tied in to Heimdal, see Figure 1.10.11. Unitization with Skirne and Byggve may be of interest.

25/5-3 SKIRNE

Production licence:	102	**Block:**	25/5
Operator:	Elf Petroleum Norge AS		
Discovery well:	25/5-3	Year:	1990
Earliest production start:		Year:	2003
Recoverable resources:		0.0	mill. Sm^3 oil
		4.2	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.9	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 0.8 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 77 million	

Gas has been proven in reservoirs from the Brent group of the Middle Jurassic Age. The drive mechanism is depressurization. The plan is to develop the discovery with a subsea installation tied in to Heimdal, see Figure 1.10.11. Unitization with Vale and Byggve may be of interest.

25/5-4 BYGGVE

Production licence:	102	**Block:**	25/5
Operator:	Elf Petroleum Norge AS		
Discovery well:	25/5-4	Year:	1991
Earliest production start:		Year:	2003
Recoverable resources:		0.0	mill. Sm^3 oil
		2.7	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.7	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 0.2 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 63 million	

25/5-4 Byggve lies between Heimdal and Skirne, see Figure 1.10.11. The discovery can be developed with a horizontal gas/condensate well from a subsea installation, and can be tied in to Heimdal. Unitization with Skirne and Vale may be of interest.

25/5-5

Production licence:	102	**Block:**	25/5
Operator:	Elf Petroleum Norge AS		
Discovery well:	25/5-5	Year:	1995
Earliest production start:		Year:	2004
Recoverable resources:		4.3	mill. Sm^3 oil
		0.0	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 0.8 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 73 million	

25/5-5 lies about six kilometers to the east of Heimdal, see Figure 1.10.11 One production well is planned.

Development with a subsea installation tied in to other installations is being considered. Production start-up depends on when capacity becomes available.

25/11-15 GRANE

Production licence:	001, 169	**Block:**	25/11
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	25/11-15	Year:	1991
Earliest production start:		Year:	2003
Recoverable resources:		112.0	mill. Sm^3 oil
		- 5.6	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 15.6 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 558 million	

The discovery, see Figure 1.10.11, is located about seven kilometers east of Balder. The reservoir contains relatively heavy oil and lies in sand with good reservoir quality in the Heimdal formation of the Paleocene Age. In 1996, a two-month test production was carried out from a horizontal well that provided valuable information on production and processing of the oil in the discovery.

The plan for development and operation of the deposit was submitted to the authorities for approval in December 1999. The plan entails development of Grane with a manned, production installation resting on the seabed with process facilities, drilling facilities and living quarters (PDQ). The installation will have a steel jacket. The plan also includes a pipeline from Grane to the Sture Terminal for export of oil as well as a pipeline from Heimdal to Grane for transportation of injection gas. The main drive mechanism for Grane will be gas injection. A total of 33 production and injection wells will be drilled. The work schedule entails that production will commence in 2003. Production capacity for oil will be 34,000 Sm^3 per day.

There are several discoveries/prospects around the Grane discovery. The plan entails that what is called the F prospect, which is probably an extension of the Grane discovery to the north, will be evaluated further and coordinated with Grane. In addition, the intention is that discovery 25/11-16 may be tied in to Grane in the event of a subsequent development.

25/11-16

Production licence:	169	**Block:**	25/11
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	25/11-16	Year:	1992
Earliest production start:		Year:	2010
Recoverable resources:		3.6	mill. Sm^3 oil
		0.0	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 0.7 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 11 million	

This discovery was made in rock of the Paleocene Age to the southwest of Grane, see Figure 1.10.11. Development is planned using subsea-completed wells tied in to Grane when Grane is coming off plateau.

25/8-10 S RINGHORNE

Production licence:	027	**Block:**	25/8
Operator:	Esso Expl. and Prod. Norway A/S		
Discovery well:	25/8-10 S	Year:	1997
Earliest production start:		Year:	2001
Recoverable resources:		30.4	mill. Sm^3 oil
		2.0	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 7.9 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 149 million	

The plan for development and operations for Ringhorne, see Figure 1.10.11, was submitted to the authorities in November 1999. Oil has been proven in source rock from the Paleocene and Early Jurassic Ages. The most important discoveries have been proven through drilling of 25/8-10 S and 25/8-11 to the northeast of Balder. 25/8-1 is also part of the discovery.

The Ringhorne development also comprises three smaller discoveries to the west and south of Balder as well as several undrilled prospects. The planned development concept is a wellhead installation and subsea-completed wells tied in to Balder FPSO. The intention is for separation to take place on the Ringhorne installation and Balder. The field will be produced using water injection and natural water drive. The intention is to start production from subsea-completed wells in 2001 and from the wellhead installation in 2002.

30/6-17

Production licence:	053	**Block:**	30/6
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	30/6-17 R	Year:	1986
Earliest production start:		Year:	2002
Recoverable resources:		0.3	mill. Sm^3 oil
		1.4	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 0 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 6 million	

This is a small oil and gas discovery in the Cook formation under the main reservoir on the Oseberg field. The deposit can be produced with one side-drilled well from the existing subsea-completed well on Oseberg, see Figure 1.10.16.

30/6-18

Production licence:	053, 079	**Block:**	30/6, 30/9
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	30/6-18	Year:	1986
Earliest production start:		Year:	2002
Recoverable resources:		1.3	mill. Sm^3 oil
		3.1	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 1.6 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 36 million	

30/6-18 is an oil discovery with a gas cap in the Statfjord formation in a structure west of Oseberg. The discovery, see Figure 1.10.16, may be developed with horizontal production wells from a subsea template and with transportation of the well stream to Oseberg for processing.

30/9-19

Production licence:	079, 190	**Block:**	30/8, 30/9
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	30/9-19	Year:	1998
Earliest production start:		Year:	2002
Recoverable resources:		2.0	mill. Sm^3 oil
		8.8	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 0 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 0 million	

30/9-19, see Figure 1.10.16, proved oil and gas in Middle Jurassic sandstone on the east flank of Oseberg. Various development concepts are being evaluated and a joint subsea development for 30/6-18 and 30/9-19 tied in to Oseberg is an alternative. The discovery can also be reached by drilling a long horizontal production well from the Oseberg field center.

34/7-23 S

Production licence:	089	**Block:**	34/7
Operator:	Saga Petroleum ASA		
Discovery well:	34/7-23 S	Year:	1994
Earliest production start:		Year:	2001
Recoverable resources:[1)]		2.9	mill. Sm^3 oil
		0.4	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 0.7 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 15 million	

1) Includes discovery 34/7-29 S H north

The discovery, see Figure 1.10.23, lies in block 34/7 southwest of the Vigdis field. Well 34/7-23 S (H west) proved oil in rocks deposited in the Late Jurassic Age. In order to improve the delimitation of the reservoir, a sidetrack was drilled from well 34/7-23 A that confirmed the discovery.

Well 34/7-29 S (H north), which is part of discovery 34/7 23 S, was drilled to explore the potential in the northern H area. This well also proved oil in rock deposited in the Late Jurassic Age. The well was formation tested in 1999. The results from the formation test and a new geological model has resulted in a downward adjustment of the resource estimate for H north.

It is assumed that pressure maintenance from water injection will be required to produce the discoveries. Based on the proven resource basis, the operator is considering a development with subsea wells phased in to Vigdis or Statfjord Øst. The plan for development and operation may be submitted to the authorities during 2000.

34/7-25 S

Production licence:	050, 089	**Block:**	34/10, 34/7
Operator:	Saga Petroleum ASA		
Discovery well:	34/7-25 S	Year:	1996
Earliest production start:		Year:	2000
Recoverable resources:		2.3	mill. Sm^3 oil
		0.2	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 0.4 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 16 million	

The discovery lies in block 34/7 to the east of the Tordis field, see Figure 1.10.23. Well 34/7-25 S proved oil in rock deposited in the Late Jurassic Age. Due to great uncertainty connected with the extent of the reservoir sand and additional resources in the surrounding segments, an appraisal well was drilled in the area in 1999. The well did not prove reservoir sand. Potential additional resources in the area was significantly reduced based on the results from this well.

Pressure support from water injection is presumed necessary to produce the discovery. Based on the proven resource basis, the operator is considering a development with wells drilled from existing subsea templates in the Tordis area.

34/11-1 KVITEBJØRN

Production licence:	193	**Block:**	34/11
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	34/11-1	Year:	1994
Earliest production start:		Year:	2004
Recoverable resources:		0.0	mill. Sm^3 oil
		49.7	bill. Sm^3 gas
		0.4	mill. tonnes NGL
		17.2	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 7.6 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 612 million	

34/11-1 Kvitebjørn lies about 20 kilometers southeast of the Gullfaks field, see Figure 1.10.23. Two exploration wells on the discovery have proven gas/condensate in Jurassic Age sandstone in the Brent group. Appraisal well 34/11-4 was drilled west of Kvitebjørn in 1999. The well proved gas/condensate in the Brent group. The discovery does not have pressure communication with Kvitebjørn. The PDO for Kvitebjørn was submitted in December 1999 and the operator has applied for gas allocation for the discovery. The development concept is a manned installation with processing equipment and a drilling module. The gas is routed to Kollsnes, while the plan is to transport the condensate through a pipeline to Mongstad. Planned start-up of gas deliveries is set at 2004.

35/8-1

Production licence: 248		**Block:**	35/8
Operator: Norsk Hydro Produksjon AS			
Discovery well:	35/8-1	Year:	1981
Earliest production start:		Year:	2010
Recoverable resources:		0.0	mill. Sm^3 oil
		11.7	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		1.8	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 1.3 billion	

The discovery is the northern one of two discoveries in the recently awarded production licence 248, see Figure 1.10.20. The discovery is located west of 35/9-1 Gjøa and north of 35/11-4 Fram and the plan is to develop the discovery together with these in a joint, but gradual development consisting of 3-4 phases. The joint project is in the process of being planned and the final decisions regarding concept and timing of phase-ins have not been made. The discovery will probably be developed in Phases 3 or 4, meaning production start-up around 2010.

35/8-2

Production licence: 248		**Block:**	35/11, 35/8
Operator: Norsk Hydro Produksjon AS			
Discovery well:	35/8-2	Year:	1982
Earliest production start:		Year:	2010
Recoverable resources:		0.0	mill. Sm^3 oil
		11.7	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		1.8	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 1.3 billion	

The discovery is the southern one of two discoveries in the recently awarded production licence 248, see Figure 1.10.20. The discovery is located west of 35/9-1 Gjøa and north of 35/11-4 Fram and the plan is to develop the discovery together with these in a joint, but gradual development consisting of 3-4 phases. The joint project is in the process of being planned and the final decisions regarding concept and timing of phase-ins have not been made. The discovery will probably be developed in Phase 3 or 4, meaning production start-up around 2010.

35/11-4 FRAM

Production licence: 090		**Block:**	35/11
Operator: Norsk Hydro Produksjon AS			
Discovery well:	35/11-4 R	Year:	1991
Earliest production start:		Year:	2003
Recoverable resources:		32.4	mill. Sm^3 oil
		17.2	bill. Sm^3 gas
		0.8	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 8.5 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 338 million	

Production licence 090 in block 35/11 was awarded in 1984. The Fram discovery lies 24 km to the north of the Troll field and consists of several structures that are gradually faulted downward from east to west, see Figure 1.10.20. So far, 11 wells and one sidetrack have been drilled in block 35/11. Of these, five wells have been drilled on what is included in the Fram discovery, in other words, the F/C complex and the H structure. These wells have proven reservoirs with a gas cap and underlying oil in the Viking and Brent group of the Jurassic Age. The reservoir quality is quite variable.

Up to the autumn of 1998, the licensees worked on an independent development concept for the Fram discovery. This concept did not provide sufficient profitability. Instead, the licensees have chosen to investigate a unitized development with Gjøa and other discoveries in the area. A unitized development will probably entail either a floater or a subsea separation facility phased in to Troll. If a subsea separation system is chosen, the development of the fields will take place gradually with the H structure in Fram as Phase 1 and the remainder of Fram as Phase 2. The work plan for unitized development entails submission of a PDO in December 2000 for Phase 1 and production start-up in 2003. The corresponding dates for Phase 2 are 2001 and 2005 respectively.

35/9-1 GJØA

Production licence: 153		**Block:**	35/9, 36/7
Operator: Norsk Hydro Produksjon AS			
Discovery well:	35/9-1 R	Year:	1989
Earliest production start:		Year:	2007
Recoverable resources:		11.6	mill. Sm^3 oil
		16.8	bill. Sm^3 gas
		0.6	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 4.9 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 140 million	

Production licence 153 was awarded in 1988. With specific conditions regarding further exploration and evaluation of the area, an extension was granted in July 1998 for 79 per cent of the area in the production licence. If the conditions are not fulfilled, at least 50 percent of the original area must be relinquished after two years, see Figure 1.10.20.

Six wells have been drilled so far within the area of the production licence, which includes several structures in blocks 35/9 and 36/7. The sixth was drilled in 1998, but technical problems prevented the collection of well data. Oil and/or gas have been proven in several reservoirs from the Jurassic Age. The main reservoirs are located in the Sognefjord and Fensfjord formations. The resources have been adjusted downward during 1998 on the basis of updated geology and reservoir studies.

A unitized development is discussed under Fram. Based on the current work plan, Gjøa will be developed as Phase 3 in a joint development of Fram and Gjøa, meaning submission of a PDO in 2003 and start-up of production in 2006.

1.10.2 NORWEGIAN SEA

FIELDS IN PRODUCTION

NJORD

Business area:	Njord Unit			
Production licence:	107, 132	**Block:**	6407/10, 6407/7	
Operator:	Norsk Hydro Produksjon AS			
Licensees:				
Den norske stats oljeselskap a.s (SDFI 30.000 %)				50.00000 %
Mobil Development Norway AS				20.00000 %
Norsk Hydro Produksjon AS				22.50000 %
Petro-Canada Norge AS				7.50000 %
Discovery well:	6407/7-1 S	Year:	1986	
Development approved:	1995	Prod.start:	1997	
Recoverable reserves:		28.4	mill. Sm^3 oil	
		0.0	bill. Sm^3 gas	
		0.0	mill. tonnes NGL	
		0.0	mill. Sm^3 cond.	
Total investments (firm 1999-NOK):		8.4 bill.		
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		497 mill.		

Production

The main reservoir is in the Tilje formation of the Jurassic Age. The field, see Figure 1.10.25, is divided into a western and an eastern segment with a complicated fault pattern. The western segment, which contains oil and a minor gas deposit, is produced by depressurization, while reinjection of produced gas is the drive mechanism for the oil-bearing eastern segment. However, alternative drive mechanisms are being evaluated. At the end of 1999, six oil producers and three gas injectors were in operation.

Production of additional resources in the main structure and in adjoining areas to the north is planned. Reproduction and export of injected gas will be assessed by the operator when sufficient operating experience from the field is available.

Development

The Njord production installation consists of a spread catenary moored, semi-submersible production, drilling and living quarters installation, see Figure 1.10.26. The installation is placed directly over the field's subsea-completed wells, which are connected to the installation via flexible risers. Of a total of 19 available risers, 15 have been installed for production and injection purposes and one is used for oil export. Two new risers will be installed in connection with planned production of additional resources. The oil processing capacity has been upgraded to 12,480 Sm^3 per day. Both the water treatment and water injection capacity is 2,500 m^3 per day respectively, with flexibility for upgrading. The gas treatment and gas injection capacity is 10 million Sm^3 per day.

Stabilized oil is transferred to the tanker that lies 2.5 km from the installation for storage and loading to shuttle tankers. The oil metering station is located on the deck of the storage ship, and stabilized oil is metered to fiscal standard in connection with transfer from storage ship to shuttle tanker.

Figure 1.10.25
Fields and discoveries in the Norwegian Sea

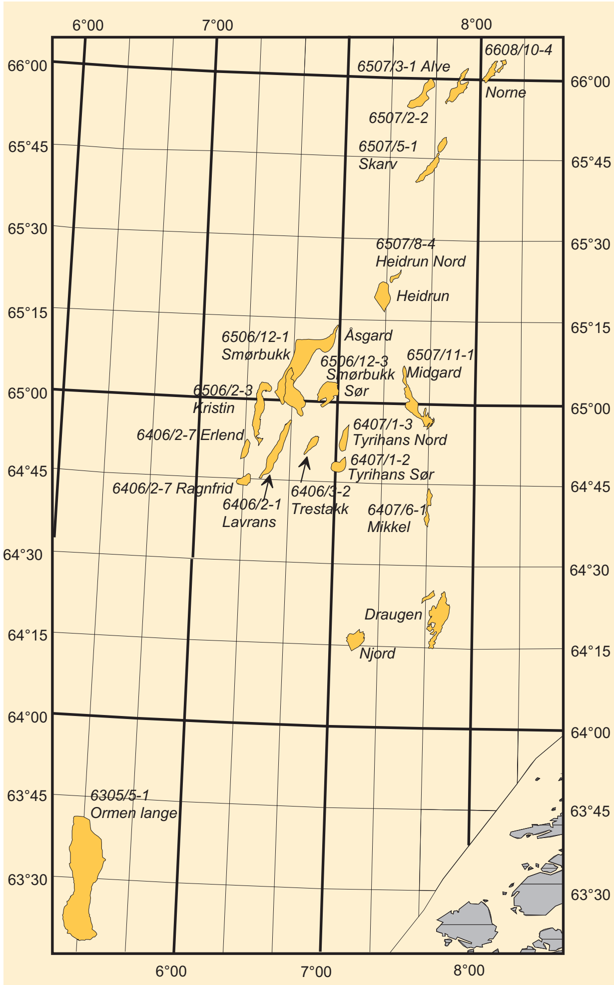
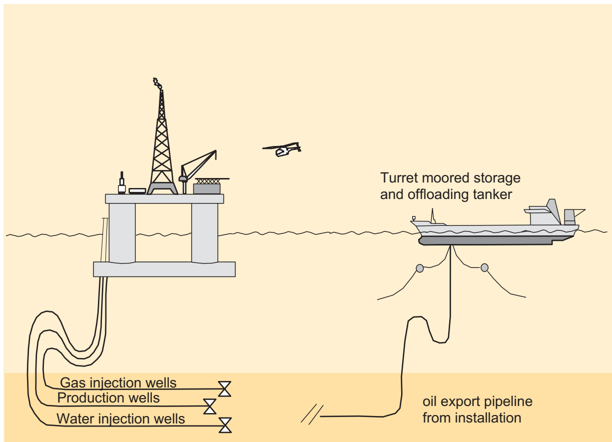


Figure 1.10.26
Installations on Njord



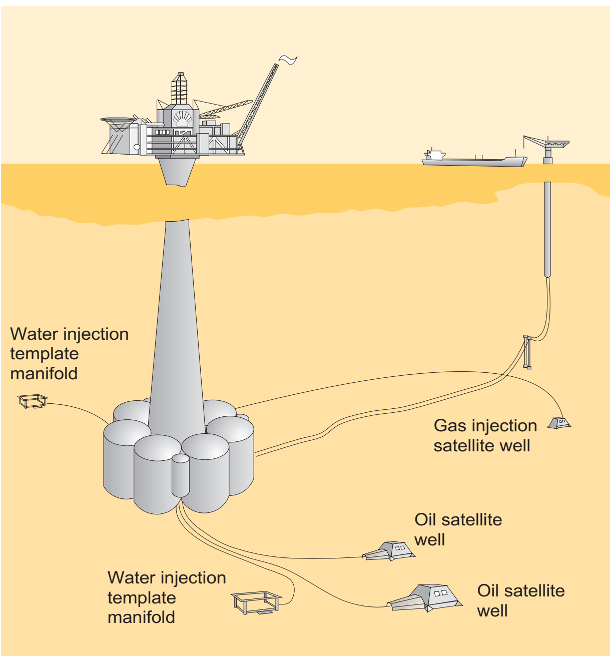
DRAUGEN

Production licence: 093		**Block:** 6407/9	
Operator: A/S Norske Shell			
Licensees:			
A/S Norske Shell			16.20000 %
BP Amoco Norge AS			18.36000 %
Den norske stats oljeselskap a.s (SDFI 57.880 %)			57.88000 %
Norsk Chevron AS			7.56000 %
Discovery well:	6407/9-1	Year:	1984
Development approved:	1988	Prod.start:	1993
Recoverable reserves:		111.6	mill. Sm^3 oil
		0.0	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		19.0 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		549 mill.	

Production
The Rogn formation of the Late Jurassic Age comprises the main reservoir. Additional resources have been proven in the Garn formation in the western part of the field, and phase-in is planned for when production from the Rogn formation begins to come off plateau in 2001/2002. In 1999, additional resources were proven in the Rogn formation in the southern part of the field (Rogn Sør).

The field, see Figure 1.10.25, produces from six wells on the installation and two subsea-completed wells. Pressure support for oil production is ensured by five subsea-completed water injection wells. Associated gas is injected via a gas injection well in a nearby water-bearing structure. From 1 October 2000, the plan is to export associated gas via the Åsgard pipeline to avoid further wasting of gas.

Figure 1.10.27
Installations on Draugen



Development
The field is developed with a concrete installation resting on the seabed with integrated topsides, see Figure 1.10.27. The installation has ten well slots and a total of 34 conductor casings. Production capacity has been upgraded to 36,000 Sm^3 per day. The water injection capacity is 42,000 m^3 per day. Treatment capacity for produced water amounts to 12,000 m^3 per day. The design capacities for gas treatment and gas injection are 1.2 and 1.04 million Sm^3 per day respectively. The daily production and injection of gas are well above the design capacities without resulting in limitations for the production of oil.

Stabilized oil is stored in tanks in the bottom of the installation. Oil is fiscally metered prior to export via floating loading buoys to tankers.

HEIDRUN

Business area:	Heidrun Unit		
Production licence:	095, 124	**Block:**	6507/8, 6707/7
Operator: Den norske stats oljeselskap a.s			
Licensees:			
Den norske stats oljeselskap a.s (SDFI 65.000 %)			76.87500 %
Fortum Petroleum AS			5.00000 %
Norske Conoco A/S			18.12500 %
Discovery well:	6507/7-2	Year:	1985
Development approved:	1991	Prod.start:	1995
Recoverable reserves:		183.8	mill. Sm^3 oil
		19.9	bill. Sm^3 gas
		0.1	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		46.2 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		1353 mill.	

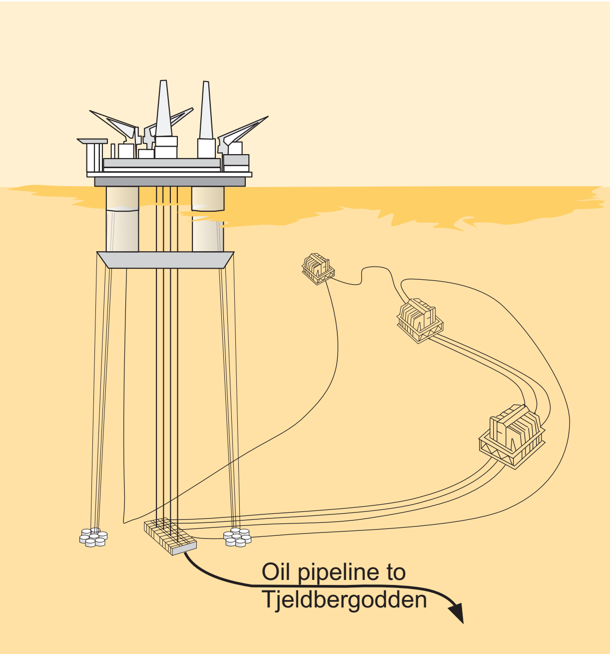
Production
The oil and gas in the field have been proven in the Garn, Ile, Tilje and Åre formations from the Jurassic Age, see Figure 1.10.25. The upper part of the reservoir is produced with the aid of water and gas injection. Production from the lower part of the reservoir is based on water injection. At the end of 1999, 17 oil producing wells, nine water injection wells and one gas injection well were in operation.

Development
The field has been developed with a floating tension leg platform of concrete installed over a subsea template with 56 well slots, see Figure 1.10.28. The northern part of the field will be produced using three subsea installations tied in to the main installation. Production capacity is 41,000 Sm^3 per day. Water treatment capacity is 24,600 m^3 per day and water injection capacity is 52,000 m^3 per day. The design capacities for gas treatment and gas injection are 6.3 and 4.3 million Sm^3 per day respectively.

The oil on Heidrun is metered to fiscal standard prior to export to Mongstad and Tetney (UK) using direct tanker transportation without using oil storage on the field. Released gas is exported to the methanol plant at Tjeldbergodden. Gas export via the Åsgard pipeline and further transportation to Kårstø and the Continent is planned starting from 1 October 2000.

The Heidrun Nord discovery has been unitized with the Heidrun field as of 1 January 2000. The discovery, see Figure 1.10.25, is located in a fault block with sandstone in the Åre formation from the Jurassic Age. The plan is to produce the discovery via Heidrun as part of the development of the Heidrun north flank. The plan for development and operations is expected in early 2000.

Figure 1.10.28
Installations on Heidrun



NORNE

Business area:	Norne Unit		
Production licence:	128, 128 B	**Block:**	6508/1, 6608/10
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 55.000 %)			79.00000 %*
Enterprise Oil Norwegian AS			6.00000 %
Norsk Agip AS			6.90000 %
Norsk Hydro Produksjon AS			8.10000 %
Discovery well:	6608/10-2	ear:	1992
Development approved:	1995	rod.start:	1997
Recoverable reserves:		80.4	mill. Sm^3 oil
		15.0	bill. Sm^3 gas
		1.4	mill. tonnes NGL
		0.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		13.1 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		594 mill.	

* Subject to approval by the Ministry of Finance

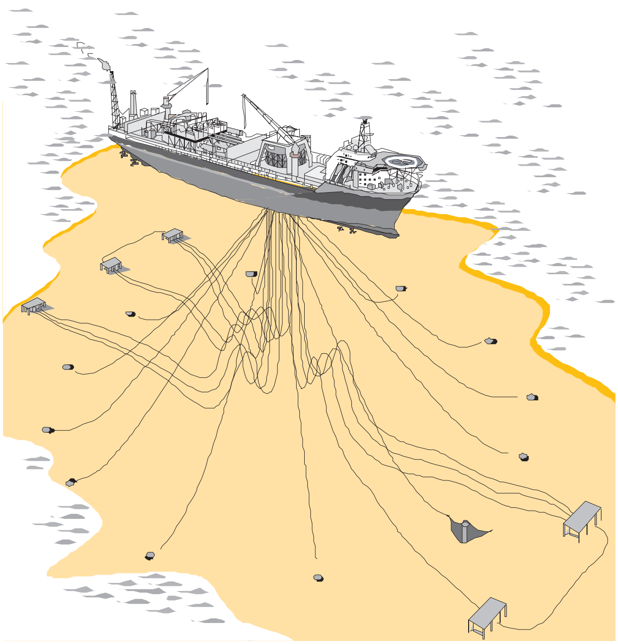
Production

The oil and gas in the Norne field, see Figure 1.10.25, has been proven in sandstone from the Jurassic Age with the oil mainly in the Ile and Tofte formations and the gas in the Garn formation. The production strategy is water injection and reinjection of produced gas. At the end of 1999, there were 10 production wells, two gas injectors and four water injectors in operation.

Development

Field development is by means of subsea installations tied in to a combined production and storage ship, see Figure 1.10.29. The subsea system consists of five well templates with four wells each and the possibility to tie in satellite wells. Production capacity for oil is 32,000 Sm^3 per day. The water treatment capacity is 20,000 m^3 per day and the water injection capacity is 38,000 m^3 per day. The ship has a gas treatment capacity of seven million Sm^3 per day, while the gas injection capacity is 6.7 million Sm^3 per day. The oil is stored in the ship before it is loaded onto shuttle tankers. Gas export via the Åsgard pipeline and further transportation to Kårstø and the Continent is planned starting from 1 October 2000.

Figure 1.10.29
Installations on Norne



ÅSGARD

Business area:	Åsgard Unit		
Production licence:	062, 074, 094, 134, 237	**Block:**	6407/2, 6407/3, 6506/11, 6506/12, 6507/11
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 46.950 %)			60.50000 %
Fortum Petroleum AS			7.00000 %
Mobil Development Norway AS			7.35000 %
Norsk Agip AS			7.90000 %
Norsk Hydro Produksjon AS			2.60000 %
Saga Petroleum ASA			7.00000 %
Total Norge AS			7.65000 %
Discovery well:	6507/11-1	ear:	1981
Development approved:	1996	rod.start:	1999
Recoverable reserves:		64.6	mill. Sm^3 oil
		198.1	bill. Sm^3 gas
		28.0	mill. tonnes NGL
		49.0	mill. Sm^3 cond.
Total investments (firm 1999-NOK):		42.8 bill.	
Operating costs (firm 1999-NOK) incl CO_2 tax, excl. tariffs, royalty and insurance:		607 mill.	

Åsgard comprises the development of the Smørbukk, Smørbukk Sør and Midgard discoveries, which are incorporated in a unitization agreement between the licensees in production licences 062, 074, 094, 134 and 237.

Åsgard lies mainly within blocks 6506/11 and 6506/12 (Smørbukk), 6506/12 (Smørbukk Sør) and 6507/11 and 6407/2 (Midgard) on Haltenbanken, about 200 kilometers from land and 50 kilometers south of the Heidrun field. Åsgard, see Figure 1.10.25, is located in an area where water depth varies from 240 to 300 meters.

Production

Smørbukk

Blocks 6506/11 and 6506/12 were awarded under production licences 094 and 134 in 1984 and 1987 respectively. Statoil was responsible for the Smørbukk discovery in 1984.

The Smørbukk discovery lies on a rotated fault block limited by faults to the west and north and structurally deeper areas towards the south and east. The reservoir formations Garn, Ile, Tofte, Tilje and Åre are from the Jurassic Age and contain gas, condensate and oil with a relatively high gas/oil ratio. The reservoir is located at depths of up to 4850 meters, which means a large portion of the reservoir has poor flow properties.

In the PDO, the operator planned to produce the Smørbukk discovery with a total of 38 wells, of which 22 were producers and 16 gas injectors. Drilling of new wells resulted in some reduction in the estimates for in-place and recoverable resources. The wells showed that the resource basis was smaller in the southern part of the discovery than previously assumed. This has led to adjustment of the production strategy and number of wells as compared with the PDO. The production strategy is initially based on reinjection of gas in order to optimize liquid recovery. The Smørbukk discovery will subsequently be produced using depressurization. Currently, 11 production wells and nine gas injectors are in operation. An additional nine production wells and two injection wells are planned for when Åsgard B comes on line.

Recoverable reserves are estimated to be 70.7 billion Sm^3 gas, 21.6 million Sm^3 oil, 37 million Sm^3 condensate and 16.1 million tonnes NGL.

Smørbukk Sør

Statoil discovered the Smørbukk Sør deposit in 1985. The petroleum trap in the Smørbukk Sør discovery is a salt dome to the northwest on the Halten terrace. The reservoir rocks in the Garn, Ile and Tilje formations are from the Early to Middle Jurassic Age and contain oil, gas and condensate.

In the PDO, the operator planned to produce the Smørbukk Sør discovery with a total of ten wells, of which seven were producers and three injectors. Subsequent optimization of the production strategy has resulted in changes to these figures. The production strategy is initially based on reinjection of gas in order to optimize oil recovery. Subsequently, the Smørbukk Sør discovery will be produced using depressurization. Currently, six production wells and three gas injection wells are in operation. An additional production well is planned for Smørbukk Sør.

Recoverable reserves are estimated to be 19.4 billion Sm^3 gas, 43 million Sm^3 oil and 2.8 million tonnes NGL.

Midgard

Blocks 6507/11 and 6407/2 were awarded under production licences 062 and 074 in 1981 and 1982 respectively. Production licence 237, awarded in 1998, comprises a minor part of block 6407/3. Saga discovered Midgard in 1981.

The petroleum trap which forms the Midgard discovery is a standing fault block (horst). The discovery is divided into four structural segments with main reservoirs in the Garn and Ile formations from the Middle Jurassic Age.

In the PDO, the operator planned to produce the Midgard discovery with a total of 12 production wells. The Midgard discovery will be produced using depressurization. As of today, the number of production wells has been reduced to 10.

Recoverable reserves for the gas zone are estimated to be 108 billion Sm^3 gas, 12 million Sm^3 condensate and 9.1 million tonnes NGL.

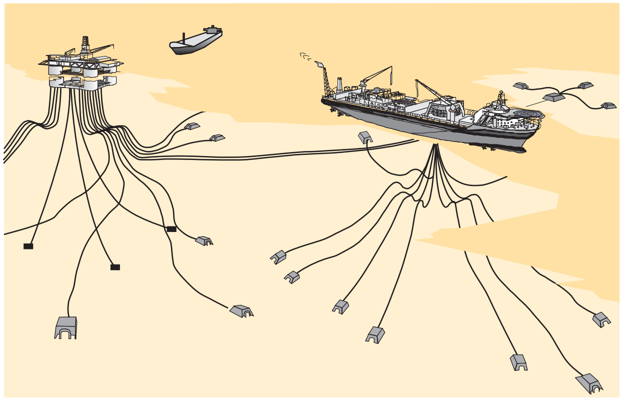
Under the gas cap on the Midgard discovery, there is a thin (11.5 meter) oil zone. An appraisal well was drilled in 1997 that confirmed the estimates of the oil resources on Midgard. Studies carried out during 1998 have shown that there is no commercial basis for producing the thin oil zone.

Development

The plan for development and operation (PDO) of Åsgard was approved by the Storting in June 1996. Åsgard will be developed in two phases; an early liquid phase that commenced production in May 1999 and a gas export phase with delivery of gas from 1 October 2000. Åsgard is to deliver 6.3 billion Sm^3 gas in the year 2000, 8.9 billion Sm^3 per year in the years 2001-2006 and 10.8 billion Sm^3 per year as from 2007.

Åsgard will be developed with subsea-completed wells connected to a semi-submersible installation for gas and condensate treatment (Åsgard B), and a production and storage ship for oil (Åsgard A), see Figure 1.10.30. A storage ship for condensate will also be connected to the gas center (Åsgard C).

Figure 1.10.30
Installations on Åsgard



The total treatment capacity is 48 million Sm^3 per day for gas, 32,000 Sm^3 per day for oil and 15,000 Sm^3 per day for condensate.

Oil and condensate will be stored temporarily on the field and transported to land using shuttle tankers. The gas will be exported in a gas pipeline from Åsgard to Kårstø.

Oil, gas and condensate will be fiscally metered on the field. The gas volumes for export will be metered using ultrasonic meters.

DISCOVERIES

6305/5-1 ORMEN LANGE

Production licence:	208, 209, 250	**Block:**	6305/4, 6305/5, 6305/7, 6305/8
Operator: Norsk Hydro Produksjon AS			
Discovery well:	6305/5-1	Year:	1997
Earliest production start:		Year:	2006
Recoverable resources:		0.0	mill. Sm^3 oil
		314.7	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		5.3	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 25.0 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 725 million	

The discovery, see Figure 1.10.25, is located in the Møre basin about 140 kilometers northwest of Kristiansund. The water depth varies between 700 to 1100 meters. The discovery is situated on the Ormen Lange dome. Well 6305/5-1 was drilled in 1997 and proved gas in sandstone in the Egga formation from the Paleocene Age. Two appraisal wells were drilled in 1998. Well 6305/7-1 in production licence 209 proved resources in the southern part of the discovery, while well 6305/1-1 to the north was dry. More work will be necessary before any development concepts can be detailed. The discovery has informally been reported to the Gas Supply Committee. The plan for development and operation may be submitted to the authorities in 2002 at the earliest. Norsk Hydro is the operator in the development phase and Norske Shell in the operations phase.

6406/2-1 LAVRANS

Production licence:	199	**Block:**	6406/2
Operator: Saga Petroleum ASA			
Discovery well:	6406/2-1	Year:	1995
Earliest production start:		Year:	2005
Recoverable resources:		0.0	mill. Sm^3 oil
		62.5	bill. Sm^3 gas
		9.4	mill. tonnes NGL
		29.1	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 6.5 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 169 million	

Three wells have been drilled during the years 1996-1999 and gas/condensate has been proven in sandstone of the Jurassic Age. The Ile, Tofte and Tilje reservoir formations lie at depths of up to 4400 meters.

The operator assumes production through depressurization.

The most interesting development solution appears to be a subsea installation tied in to existing or new infrastructure in the area, see Figure 1.10.25.

Work has proceeded towards establishing a coordinated development of the discoveries in production licences 199 and 134, probably with 6406/2-3 Kristin as the field center. The PDO may be submitted to the authorities in 2001.

6406/2-3 KRISTIN

Production licence:	134, 199	**Block:**	6406/2, 6506/11
Operator: Saga Petroleum ASA			
Discovery well:	6406/2-3	Year:	1997
Earliest production start:		Year:	2005
Recoverable resources:		0.0	mill. Sm^3 oil
		39.1	bill. Sm^3 gas
		5.9	mill. tonnes NGL
		42.1	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 11.2 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 1 billion	

Three wells and one sidetrack have been drilled during the period 1996-1998 and gas/condensate has been proven in sandstone in the Garn and Ile formations of the Jurassic Age, see Figure 1.10.25.

A potential production strategy is injection of gas in order to optimize liquid recovery. However, a high initial reservoir pressure, combined with a relatively low dewpoint pressure, means that gas injection is not relevant until after a few years of gas production.

The most interesting development solution appears to be an independent production installation or, alternatively, a subsea installation tied in to existing infrastructure in the area.

Work has proceeded towards establishing a coordinated development of the discoveries in production licenses 199 and 134, probably with 6406/2-3 Kristin as the field center. The PDO may be submitted to the authorities in 2001.

6406/2-6 RAGNFRID

Well 6406/2-6, see Figure 1.10.25, was drilled during the second half of 1998. The well was not production tested, but liquid samples proved gas/condensate in sandstone from the Middle Jurassic Age. The structure extends into areas that have not been awarded yet. The plan is to delimit the structure by means of drilling an appraisal well upflank on the structure. The drilling of an appraisal well is dependent on the awarding of the neighboring blocks or block areas that comprise the structure. The discovery is included in an ongoing evaluation of a unitized development of this area. The plan for development and operation may be submitted as early as 2001.

6406/2-7 ERLEND

Well 6406/2-7, see Figure 1.10.25, was drilled towards the end of 1999. Gas/condensate has been proven in sandstone of the Middle Jurassic Age. The structure extends into the neighboring block 6406/1 that has not been awarded yet. The plan is to delimit the structure by means of drilling a sidetrack. The drilling of an appraisal well is dependent on the awarding of acreage in the neighboring block. The discovery is included in an ongoing evaluation of a unitized development of this area. The plan for development and operation may be submitted as early as 2001.

6407/1-2 TYRIHANS

Production licence:	073, 091	**Block:**	6406/3, 6407/1
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	6407/1-2	Year:	1983
Earliest production start:		Year:	2009
Recoverable resources:		0.0	mill. Sm^3 oil
		23.0	bill. Sm^3 gas
		4.0	mill. tonnes NGL
		19.4	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 4.1 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 89 million	

6407/1-2 Tyrihans, see Figure 1.10.25, consists of two structures, Tyrihans Sør and Tyrihans Nord. The Tyrihans Sør discovery was made in 1983 and the Tyrihans Nord discovery was made in 1984 in production licence 073. The discoveries are probably in pressure communication through a common water zone. Tyrihans Sør is characterized as a gas/condensate discovery, while Tyrihans Nord contains an oil zone with overlying gas cap. The reservoirs are from the Middle Jurassic Age. An appraisal well was drilled on the Tyrihans Nord discovery in 1996. The well proved gas, oil and water. The transition zone makes it difficult to determine the oil/water contact exactly. There is uncertainty connected with the oil resources in Tyrihans Nord.

The most likely production strategy is based on depressurization of the Tyrihans Nord discovery and gas injection in the Tyrihans Sør discovery in order to optimize liquid recovery. Several potential development concepts are being evaluated. The most interesting development solution for Tyrihans appears to be a satellite to existing or new infrastructure in the area, or alternatively an independent floating production installation.

6407/6-3 MIKKEL

Production licence:	092, 121	**Block:**	6407/5, 6407/6
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	6407/6-3	Year:	1986
Earliest production start:		Year:	2002
Recoverable resources:		1.6	mill. Sm^3 oil
		19.5	bill. Sm^3 gas
		4.7	mill. tonnes NGL
		4.6	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 1.8 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 109 million	

6407/6-3 Mikkel, see Figure 1.10.25, is a gas discovery with a thin oil zone that was made in 1987. The reservoir lies at a depth of about 2500 meters and is made up of sandstone in the Garn and Ile formations of Middle Jurassic Age. An appraisal well was drilled in 1999 that confirmed the discovery. The production strategy will most likely be depressurization from three gas production wells. The licensees have applied for gas allocation.

The plan is to develop Mikkel by means of subsea installations tied in to existing infrastructure in the area for processing and transportation. The licensees are preparing a plan for development and operations for submission in the summer of 2000.

6507/5-1 SKARV

Production licence:	159, 212	**Block:**	6507/3, 6507/5, 6507/6
Operator:	BP Amoco Norge AS		
Discovery well:	6507/5-1	Year:	1998
Earliest production start:		Year:	2005
Recoverable resources:		18.3	mill. Sm^3 oil
		29.9	bill. Sm^3 gas
		0.0	mill. tonnes NGL
		3.7	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 6.3 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 370 million	

Well 6507/5-1 proved oil and gas in sandstone of both the Jurassic and Cretaceous Ages. Three separate production tests were conducted; two in sandstone of Jurassic Age and one in sandstone of Cretaceous Age. Appraisal well 6507/5-2, which was drilled in 1999, did not determine the size of the discovery. A new appraisal well is therefore planned to determine the size of the discovery and the oil-gas ratio. Different field development concepts are being evaluated for the area with 6507/5-1 Skarv as a possible field center for oil production and gas export if tied in to existing infrastructure.

1.10.3 BARENTS SEA

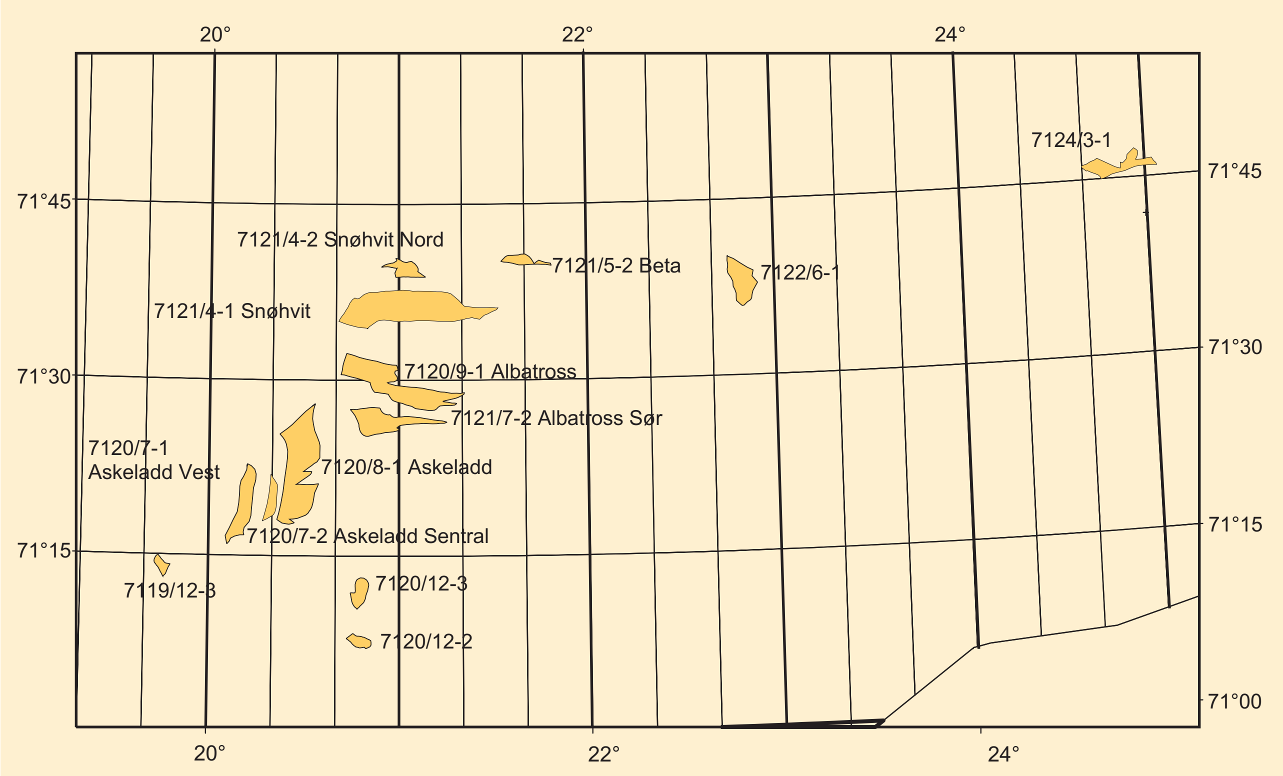
DISCOVERIES

SNØHVIT AREA

The Snøhvit area consists of production licences 064, 077, 078, 097, 099, 100 and 110. The largest discoveries in the Snøhvit area include 7121/4-1 Snøhvit, 7120/8-1 Askeladd and 7120/9-1 Albatross. 7121/4-1 Snøhvit, 7120/8-1 Askeladd and 7120/9-1 Albatross are included in the development concepts that are being evaluated. Volumes from 7121/4-2 Snøhvit Nord and 7121/5-2 Beta and other small discoveries in the area are not included in the development plans. The investment estimate is based on the assumption that the Snøhvit oil is produced and exported from a floating installation on Snøhvit. Gas and condensate are sent to Melkøya just outside of Hammerfest via a multiphase pipeline. The gas will be produced simultaneously from Snøhvit and Askeladd, while Albatross will be phased in later. The concept is based on 40 wells; 15 oil producers, 17 gas producers and eight injectors. The gas will be processed and converted to liquid (LNG) in facilities on Melkøya and shipped to the market in custom-built tankers.

A pure gas concept based on subsea production and pipeline transportation of gas/condensate to Melkøya for

Figure 1.10.31
Discoveries in the Barents Sea



processing and conversion to LNG is an important competitor to development concepts that entail both oil and gas production. The licensees are preparing a plan for development and operation for submission around 2000/2001.

7121/4-1 SNØHVIT

Production licence:	097, 099, 110	**Block:**	7120/6, 7121/4, 7121/5
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	7121/4-1	Year:	1984
Earliest production start:		Year:	2006
Recoverable resources:		20.8	mill. Sm^3 oil
		176.3	bill. Sm^3 gas
		5.7	mill. tonnes NGL
		18.5	mill. Sm^3 cond.
Total investments (firm 1999 NOK):		NOK 23.3 billion	
Maximum annual operating costs incl. CO_2 tax, excl. tariffs, royalty and insurance (firm 1999 NOK):		NOK 724 million	

The Snøhvit discovery, see Figure 1.10.31, is a gas/condensate discovery with a thin oil zone. The reservoir consists of an east-west running, fault-controlled structure centrally located in the Hammerfest basin. The structure has wide lateral extension, about 130 km^2. The reservoir was proven in wells 7121/5-1, 7121/4-1 and 7120/6-1 and consists of sandstone from the Early and Middle Jurassic Age. In well 7121/4-1 S, some gas was also proven in sandstone of Late Triassic/Early Jurassic Age under the oil zone.

7120/8-1 ASKELADD

Askeladd consists of four main structures of various depth down to the gas/water contact, see Figure 1.10.31. During the period 1981 - 1983, the wells 7120/7-1, 7120/7-2, 7120/8-1 and 7120/8-2 proved gas in sandstone of Early and Middle Jurassic Age in these structures.

7120/9-1 ALBATROSS

Albatross consists of two main structures of various depth down to the gas/water contact, see Figure 1.10.31. During the period 1982 - 1986, the wells 7120/9-1 and 7121/7-1 proved gas in sandstone of Middle Jurassic Age in these structures. Well data from 7121/7-1 in the southern structure may indicate the presence of a thin stratigraphic oil leg of 1-3 meters under the gas column.

FIELDS WHERE PRODUCTION HAS CEASED

ALBUSKJELL

Production licence:	018, 018 B	**Block:** 1/6, 2/4	
Operator:	Phillips Petroleum Company Norway		
Discovery well:	1/6-1	Year:	1972
Development approved:	1975	Prod.start:	1979
		Prod. cease:	1998
Reserves, recovered:		7.4 mill. Sm^3 oil 15.9 bill. Sm^3 gas 1.0 mill. tonnes NGL	
Total investments (firm 1999 NOK):		9.3 bill.	

Disposal
Production from Albuskjell was halted in connection with start-up of Ekofisk II and feasibility studies have been performed to evaluate profitable production of remaining resources. The licensees are considering the possibility of resuming production from the field at a later point in time with existing installations as unlikely.

COD

Production licence:	018	**Block:** 7/11	
Operator:	Phillips Petroleum Company Norway		
Discovery well:	7/11-1	Year:	1968
Development approved:	1973	Prod.start:	1977
		Prod. cease:	1998
Reserves, recovered:		2.9 mill. Sm^3 oil 7.5 bill. Sm^3 gas 0.5 mill. tonnes NGL	
Total investments (firm 1999 NOK):		3.9 bill.	

Disposal
Production from the field was ceased in August 1998. At shutdown, it was estimated that about 70 per cent of the original gas in place had been produced. Production of the remaining gas is not considered to be profitable. The Cod installation is shut down and the wells were permanently plugged in 1999.

EDDA

Production licence:	018	**Block:** 2/7	
Operator:	Phillips Petroleum Company Norway		
Discovery well:	2/7-4	Year:	1972
Development approved:	1975	Prod.start:	1979
		Prod. cease:	1998
Reserves, recovered:		4.8 mill. Sm^3 oil 2.1 bill. Sm^3 gas 0.2 mill. tonnes NGL	
Total investments (firm 1999 NOK):		6.9 bill.	

Production from the field was halted in August 1998 when Ekofisk II was put into production. The licensees submitted a report to the authorities in December 1999 that concluded that remaining resources could not be produced profitably. The installation is now temporarily shut down until a final decision is made regarding shutdown or subsequent resumption of production.

LILLE-FRIGG

Production licence:	026	**Block:** 25/2	
Operator:	Elf Petroleum Norge AS		
Discovery well:	25/2-4	Year:	1975
Development approved:	1991	Prod.start:	1994
		Prod. cease:	1999
Reserves, recovered:		2.3 bill. Sm^3 gas 1.3 mill. Sm^3 cond.	
Total investments (firm 1999 NOK):		4.8 bill.	

Disposal
Production from Lille-Frigg was ceased in March 1999. It is expected that the Storting will consider the decommissioning plan in the spring of 2000.

Disposal of pipelines and cables will be determined in light of the clarification program for pipeline disposal.

MIME

Production licence:	070	**Block:** 7/11	
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	7/11-5	Year:	1982
Development approved:	1992	Prod.start:	1990
		Prod. cease:	1993
Reserves, recovered:		0.4 mill. Sm^3 oil 0.1 bill. Sm^3 gas	
Total investments (firm 1999 NOK):		0.4 bill.	

Disposal
The decommissioning plan for Mime was approved in 1996. The installation was brought to land for scrapping in 1999. Disposal of the pipeline to Cod will be determined in light of the clarification program for pipeline disposal.

NORDØST FRIGG

Production licence:	024, 030	**Block:** 25/1, 30/10	
Operator:	Elf Petroleum Norge AS		
Discovery well:	25/1-4	Year:	1974
Development approved:	1980	Prod.start:	1983
		Prod. cease:	1993
Reserves, recovered:		11.6 bill. Sm^3 gas	
Total investments (firm 1999 NOK):		3.7 bill	
Accrued disposal costs (firm 1999 NOK):		74 mill.	

Disposal
The control station and foundation on Nordøst Frigg were disconnected from the seabed and transported to land as one unit. The deck has been deposited on land and functions as a training center, the steel column is used as a breakwater in a marina for small boats, and the concrete foundation is used as an anchoring point for the breakwater.

The subsea installation has been brought ashore and scrapped.

ODIN

Production licence:	030	**Block:** 30/10	
Operator:			
Discovery well:	30/10-2	Year:	1974
Development approved:	1980	Prod.start:	1984
		Prod. cease:	1994
Reserves, recovered:		29.3 bill. Sm^3 gas	
Total investments (firm 1999 NOK):		5.3 bill.	
Accrued disposal costs (firm 1999 NOK):		104 mill.	

Disposal
The installations on the Odin field have been transported to land for scrapping and recycling. Disposal of the pipeline to Frigg will be determined in light of the clarification program for pipelines.

TOMMELITEN GAMMA

Production licence:	044	**Block:** 1/9	
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	1/9-4	Year:	1978
Development approved:	1986	Prod.start:	1988
		Prod. cease:	1998
Reserves, recovered:		3.9 mill. Sm^3 oil 9.2 bill. Sm^3 gas 0.6 mill. tonnes NGL	
Total investments (firm 1999 NOK):		3.6 bill.	

Resource management

Disposal

The installation was shut down in connection with the shutdown of Ekofisk I in the summer of 1998. The licensees are considering the possibility of resuming production at a later point in time, but this seems unlikely in light of the Edda conclusions. The decommissioning plan for Tommeliten Gamma was submitted to the authorities in the summer of 1997, but no decision has been made regarding permanent shutdown and disposal.

VEST EKOFISK

Production licence:	018	**Block:** 2/4	
Operator:	Phillips Petroleum Company Norway		
Discovery well:	2/4-6	Year:	1970
Development approved:	1973	Prod.start:	1977
		Prod. cease:	1998
Reserves, recovered:		12.2 mill. Sm^3 oil 26.9 bill. Sm^3 gas 1.4 mill. tonnes NGL	
Total investments (firm 1999 NOK):		3.0 bill.	

Disposal

Production from Vest Ekofisk was halted in connection with start-up of operations on Ekofisk II, however, it is estimated that the remaining reserves may be produced commercially at a later point in time. The installation is now shut down and the wells will be permanently plugged. The licensees are considering resuming production from the field at a later point in time with a new subsea installation and horizontal wells.

ØST FRIGG

Production licence:	024, 026, 112	**Block:** 25/1, 25/2	
Operator:	Elf Petroleum Norge AS		
Discovery well:	25/2-1	Year:	1973
Development approved:	1984	Prod.start:	1988
		Prod. cease:	1997
Reserves, recovered:		9.4 bill. Sm^3 gas 0.1 mill. Sm^3 cond.	
Total investments (firm 1999 NOK):		3.3 bill.	
Accrued disposal costs (firm 1999 NOK):		103 mill.	

Disposal

The Storting approved the decommissioning plan for Øst Frigg in 1999. The installation is scheduled to be brought to land for scrapping and condemnation in 2002 - 2003.

Disposal of pipelines and cables will be determined in light of the clarification program for pipeline disposal.

1.10.4 DEVELOPMENT DRILLING

Since 1973, 1,653 development wells have been spudded on the Norwegian continental shelf; 1.539 of these in the North Sea and 114 in the Norwegian Sea where drilling started in 1992. 1,241 are production wells, 295 inject water, gas or some other medium and 117 are observation wells. 722 are currently out of service, temporarily abandoned for later completion, or shut down for other reasons.

The wells have been drilled from 166 permanent installations (stationary, floating or subsea templates). Drilling was in progress on 17 development wells as of 31 December 1999.

Figure 1.10.32
Development wells on the Norwegian continental shelf 1973-1999

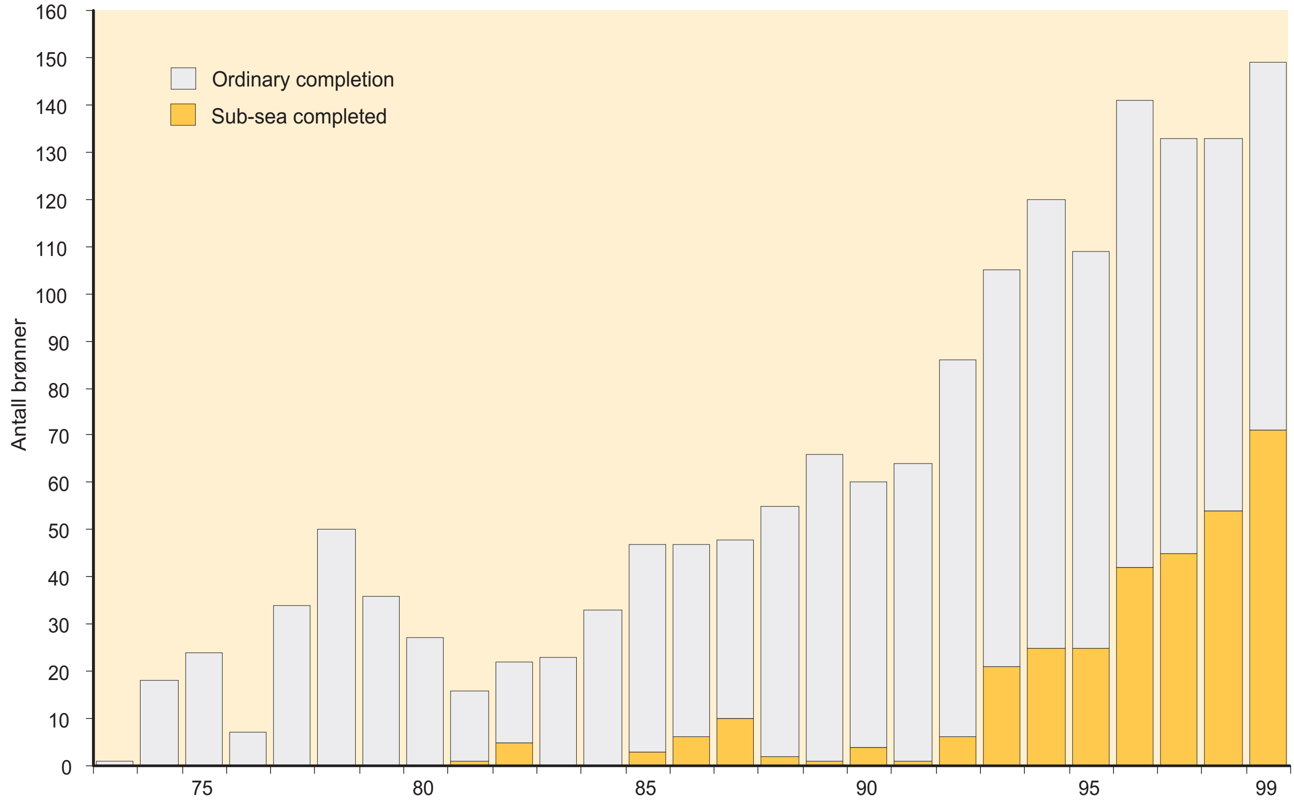


Figure 1.10.32 shows development wells spudded per year during the period 1973-1999.

As of 31 December 1999, production or injection is carried out from 103 installations divided among 56 fields.

In 1999, 149 development wells were spudded on 30 fields; 118 in the North Sea and 31 in the Norwegian Sea.

85 of the wells, i.e. 57 per cent, were drilled from 20 different mobile units.

The number of subsea-completed wells has shown a strong increase over the last eight years. This increase was particularly marked from 1995 to 1999 when the number of subsea-completed wells went up from 25 to 71, see Figure 1.10.32. This means that the percentage of subsea-completed wells drilled per year has increased from 7 per cent in 1992 to 48 per cent in 1999.

1.11 TRANSPORTATION SYSTEMS FOR OIL AND GAS

1.11.1 EXISTING TRANSPORTATION SYSTEMS

The various transportation systems are shown in Figure 1.11.1.

Gas transportation

Haltenpipe

Ownership structure

Norske Conoco A/S	18.12500 %
Den norske stats oljeselskap a.s (SDFI: 65.00000%)	76.87500 %
Fortum Petroleum AS	5.00000 %

Haltenpipe is a 245 kilometer pipeline with an outer diameter of 16" for transportation of gas from Heidrun to Tjeldbergodden. The pipeline has a capacity of 2-2.5 billion Sm^3 per year. The pipeline was put into operation in 1997. The owners are the same as for Heidrun and Statoil is the operator.

Statpipe

Ownership structure

Saga Petroleum ASA	2.00000 %
A/S Norske Shell	5.00000 %
Total Norge AS	2.00000 %
Esso Expl. and Prod. Norway A/S	5.00000 %
Mobil Development Norway AS	7.00000 %
Norsk Hydro Produksjon AS	8.00000 %
Den norske stats oljeselskap a.s	58.25000 %
Norske Conoco A/S	2.75000 %
Elf Petroleum Norge AS	10.00000 %

The Statpipe system comprises:

- a rich gas pipeline from Statfjord to Kårstø. The transportation capacity for pipelines from Statfjord to Kårstø is 8 billion Sm^3 per day. The pipeline has an outer diameter of 30".
- separation and fractionating plant at Kårstø, plus storage and loading facility.
- a dry gas pipeline from Heimdal to the Draupner S riser installation with a length of 155 kilometers and an outer diameter of 36", a dry gas pipeline from Kårstø to Draupner S with a length of 228 kilometers and an outer diameter of 28", and a pipeline from Draupner S to the Ekofisk Bypass with a length of 188 kilometers and an outer diameter of 36".

Statoil is the operator for Statpipe, a 880-kilometer pipeline network with two riser installations and a gas-processing terminal on Kårstø. The fields Statfjord, Gullfaks, Snorre, Brage, Tordis and Veslefrikk are tied in to the Statpipe system upstream of Kårstø. Rich gas is transported through Statpipe to Kårstø, where wet gas is separated and fractionated into products which then are transported with ships. Dry gas is transported in a pipeline to the riser installation Draupner S and then on to Emden via the Ekofisk Bypass and Norpipe. Heimdal is tied in to the Statpipe pipeline via a pipeline to the Draupner S riser installation.

Sleipner is connected to Statpipe via a branch pipeline to Draupner.

Kårstø

Delivery of dry gas from the gas-processing terminal in Kårstø began in October 1985. The facilities receive rich gas from the Statpipe system and condensate from Sleipner. The Kårstø facilities consist of two fractionating/distillation lines for methane (dry gas), ethane, propane, butane and naphtha and one fractionating line for stabilization of condensate. The heavy hydrocarbons are removed from the wet gas and sold as propane, butane, methyl propane and naphtha. The condensate from Sleipner is split into propane, butane, methyl propane and condensate and shipped on to the customers. Propane, butane, methyl propane, naphtha and condensate are stored in separate tanks, prior to being pumped via fiscal metering equipment to tankers.

Dry gas is transported in the Statpipe pipeline from Kårstø to the riser installation Draupner S and then on to Emden in Germany. Europipe II started transportation of dry gas from Kårstø to Dornum in Germany in October 1999.

In October 2000, deliveries of rich gas started through the Åsgard Transport from inter alia the Åsgard field. Two new fractionating/distillation lines are being built to process the gas. New storage for propane is also under construction. The gas treatment facility has a capacity of 25 million Sm^3 per day (about 8 billion Sm^3 per year) and the condensate facility has a capacity of 3.6 million tonnes per year.

Frigg transport

Ownership structure

Total Norge AS	16.71000 %
Norsk Hydro Produksjon AS	32.87000 %
Den norske stats oljeselskap a.s	29.00000 %
Elf Petroleum Norge AS	21.42000 %

The Frigg Norwegian pipeline (FNA) is owned by the Norwegian Frigg licensees. Total Norge AS is technical opera-

Resource management

tor of the pipeline. FNA is 365 kilometers long and has an outer diameter of 32». The pipeline has a capacity of about 10 billion Sm^3 per year.

Some British fields are connected to the FNA via MCP-01 (compressor station). While the installation was manned, the volumes from the British fields were metered on MCP-01. After demanning, the volumes from the British fields are metered on the individual installation.

Zeepipe
Ownership structure

Norske Conoco A/S	1.40299 %
Total Norge AS	1.29851 %
Saga Petroleum ASA	3.00000 %
Esso Expl. and Prod. Norway A/S	6.00000 %
A/S Norske Shell	7.00000 %
Norsk Hydro Produksjon AS	8.00000 %
Den norske stats oljeselskap a.s (SDFI: 55.00000%)	70.00000 %
Elf Petroleum Norge AS	3.29850 %

Zeepipe is a gas transportation system that is to transport gas from Kollsnes in Øygarden to the Continent. Phase I of the project comprises an 800-kilometer pipeline with an outer diameter of 40" from Sleipner to Zeebrügge in Belgium. In addition, an approximately 40-kilometer line has been laid from Sleipner to the Draupner installation (16/11 S). Phase I, including the Zeebrügge terminal, was completed in 1993. The capacity without compression is about 12.6 billion Sm^3 per year.

Phase II comprises two pipelines from Kollsnes to Sleipner R and the Draupner installation respectively. The pipeline to Sleipner R, Phase II-A, was put into operation in 1996 and the pipeline to Draupner, Phase II-B, was put into operation in 1997.

Statoil is the operator.

Europipe I
Ownership structure

Norske Conoco A/S	1.40299 %
Total Norge AS	1.29851 %
Elf Petroleum Norge AS	3.29850 %
Saga Petroleum ASA	3.00000 %
Esso Expl. and Prod. Norway A/S	6.00000 %
Norsk Hydro Produksjon AS	8.00000 %
Den norske stats oljeselskap a.s (SDFI: 55.00000%)	70.00000 %
A/S Norske Shell	7.00000 %

This pipeline goes from Draupner (16/11 E) to Emden in Germany and is about 620 kilometers long and has an outer diameter of 40". The capacity without compression is approximately 13 billion Sm^3 gas per year. Gas deliveries started as planned on 1 October 1995.

Statoil is the operator.

Europipe II

A/S Norske Shell	1.18120 %
Den norske stats oljeselskap a.s (SDFI: 60.00000%)	60.01000 %
Elf Petroleum Norge AS	0.00590 %
Esso Expl. and Prod. Norway A/S	7.67790 %
Mobil Development Norway AS	1.18120 %
Norsk Agip AS	2.36240 %
Norsk Hydro Produksjon AS	4.72490 %
Norske Conoco A/S	2.65770 %
Saga Petroleum ASA	10.63090 %
Total Norge AS	5.90610 %
Fortum Petroleum AS	3.66180 %

Europipe II is a 653 kilometer pipeline with an outer diameter of 42" for transportation of gas from Kårstø to Dornum. The pipeline has a capacity of 21.1 billion Sm^3 per year and was put into operation on 1 October 1999. Statoil is the operator of Europipe II.

Norpipe gas pipeline
Ownership structure

Norpipe A/S	100%

The pipeline system for transportation of natural gas from the Ekofisk Center to Emden in Germany is owned by Norpipe A/S. Gas from the Ekofisk area, Valhall and Statpipe is delivered to Norpipe. Norpipe A/S is a corporation that is 100%-owned by Norsea Gas A/S.

Phillips Petroleum Company Norway is the technical operator of the pipeline, and is responsible for the financial and administrative functions.

A bypass line from Statpipe to Norpipe bypassing the Ekofisk Center has been laid in connection with Ekofisk II. In addition, Valhall is connected to Norpipe downstream of the Ekofisk Center.

The gas pipeline is 442 kilometers long and has an outer diameter of 36". The design capacity for the gas pipeline is about 19 billion Sm^3 per year.

There are two compressor stations on the gas pipeline, both on the German continental shelf. Norpipe is connected to Europipe so that gas from Norpipe can be delivered via the Europipe system and vice versa.

Franpipe
Ownership structure

Norske Conoco A/S	1.29450 %
A/S Norske Shell	1.29450 %
Norsk Agip AS	1.94170 %
Elf Petroleum Norge AS	2.13590 %
Total Norge AS	2.91260 %
Mobil Development Norway AS	3.88350 %
Esso Expl. and Prod. Norway A/S	3.88350 %
Saga Petroleum ASA	5.17800 %
Norsk Hydro Produksjon AS	6.47250 %
Den norske stats oljeselskap a.s (SDFI: 60.00000%)	69.70880 %
Fortum Petroleum AS	1.29450 %

Franpipe is an 840-kilometer pipeline with an outer diameter of 42" between Draupner (16/11 E) and Dunkerque in France. The pipeline has an initial capacity of 11.4 billion Sm^3 per year, which can be increased by changing the operational pressure regime. Gas deliveries started in the autumn of 1998. Franpipe was previously called NorFra. The name change took place in the autumn of 1999.

Statoil is the operator.

Norsea Gas
Ownership structure

Norsea Gas A/S	100%

Phillips Petroleum Norsk AS is operator on behalf of the Phillips Group. The Norpipe system is connected to Europipe so that gas from Norpipe can be delivered via the Europipe system and vice versa.

Oil transportation

Troll Oljerør (Troll oil pipeline)
Ownership structure

Total Norge AS	1.35343 %
Saga Petroleum ASA	2.04000 %
Norske Conoco A/S	1.66113 %
Norsk Hydro Produksjon AS	7.68800 %
Elf Petroleum Norge AS	2.35344 %
Den norske stats oljeselskap a.s (SDFI: 62.69600%)	76.61600 %
A/S Norske Shell	8.28800 %

Troll Oljerør I and Troll Oljerør II transport oil from the Hydro-operated Troll B and Troll C installations to Mongstad. Statoil is the operator of the pipeline systems.

Troll I is a 16" pipeline that was put into operation in the summer of 1995. Troll II is a 20" pipeline that was put into operation in the autumn of 1999.

Oseberg Transport System (OTS)
Ownership structure

Mobil Development Norway AS	4.32720 %
Total Norge AS	2.88480 %
Saga Petroleum ASA	8.55276 %
Norsk Hydro Produksjon AS	13.68186 %
Den norske stats oljeselskap a.s (SDFI: 50.78379%)	64.78379 %
Elf Petroleum Norge AS	5.76959 %

A pipeline for transportation of stabilized oil from Oseberg to the Sture terminal was laid in the summer of 1987. The pipeline has an outer diameter of 28" and has a design capacity of approximately 95,000 Sm^3 per day. By adding drag reducers, the capacity has been increased to about 117,000 Sm^3 per day.

The plant, including the terminal at Sture, is owned and operated by a separate joint venture, I/S Oseberg Transport System. The participants in the company are the licensees in the Oseberg field. Norsk Hydro is the operator of the pipeline and the terminal. OTS was put into operation when production started from Oseberg. Veslefrikk, Brage, Frøy and Lille-Frigg have subsequently been connected to OTS.

Frostpipe
Ownership structure

Total Norge AS	14.25000 %
Norsk Hydro Produksjon AS	13.75000 %
Den norske stats oljeselskap a.s (SDFI: 30.00000 %)	50.00000 %
Elf Petroleum Norge AS	22.00000 %

Frostpipe is an approximately 80-kilometer pipeline with an outer diameter of 16" for transportation of stabilized oil and condensate from Frigg and Oseberg. The transportation system has a capacity of about 16,000 Sm^3 per day. Production start was in the spring of 1994. A further link between Heimdal and the Frøy area is currently being evaluated.

Sleipner condensate pipeline
Ownership structure

Den norske stats oljeselskap a.s. (SDFI 29,600000 %)	49.600000 %
Elf Petroleum Norge AS	10.000000 %
Esso Expl. and Prod. Norway A/S	30.400000 %
Norsk Hydro Produksjon AS	10.000000 %

The Sleipner condensate pipeline transports unstabilized condensate (condensate and NGL) from Sleipner Øst, Sleipner Vest, Loke and Gungne to Kårstø. The pipeline is about 250 kilometers long and has an outer diameter of 20". The capacity is up to 29,000 Sm^3 unstabilized condensate per day depending on the composition of the condensate.

Ula oil transportation
Ownership structure

Den norske stats oljeselskap a.s.	100 %

Ula transport consists of the Ula pipeline and the Gyda pipeline. The pipelines transport oil and NGL from Ula and Gyda to Ekofisk for further transportation via Norpipe's oil pipeline to Teesside in the UK. The pipeline from Ula to Ekofisk is 70 kilometers long with a diameter of 20" and has been in operation since 1986. The pipeline from Gyda to the Ula pipeline is 25 kilometers long with a diameter of 20" and has been in operation since 1990.

Norpipe oil pipeline
Ownership structure

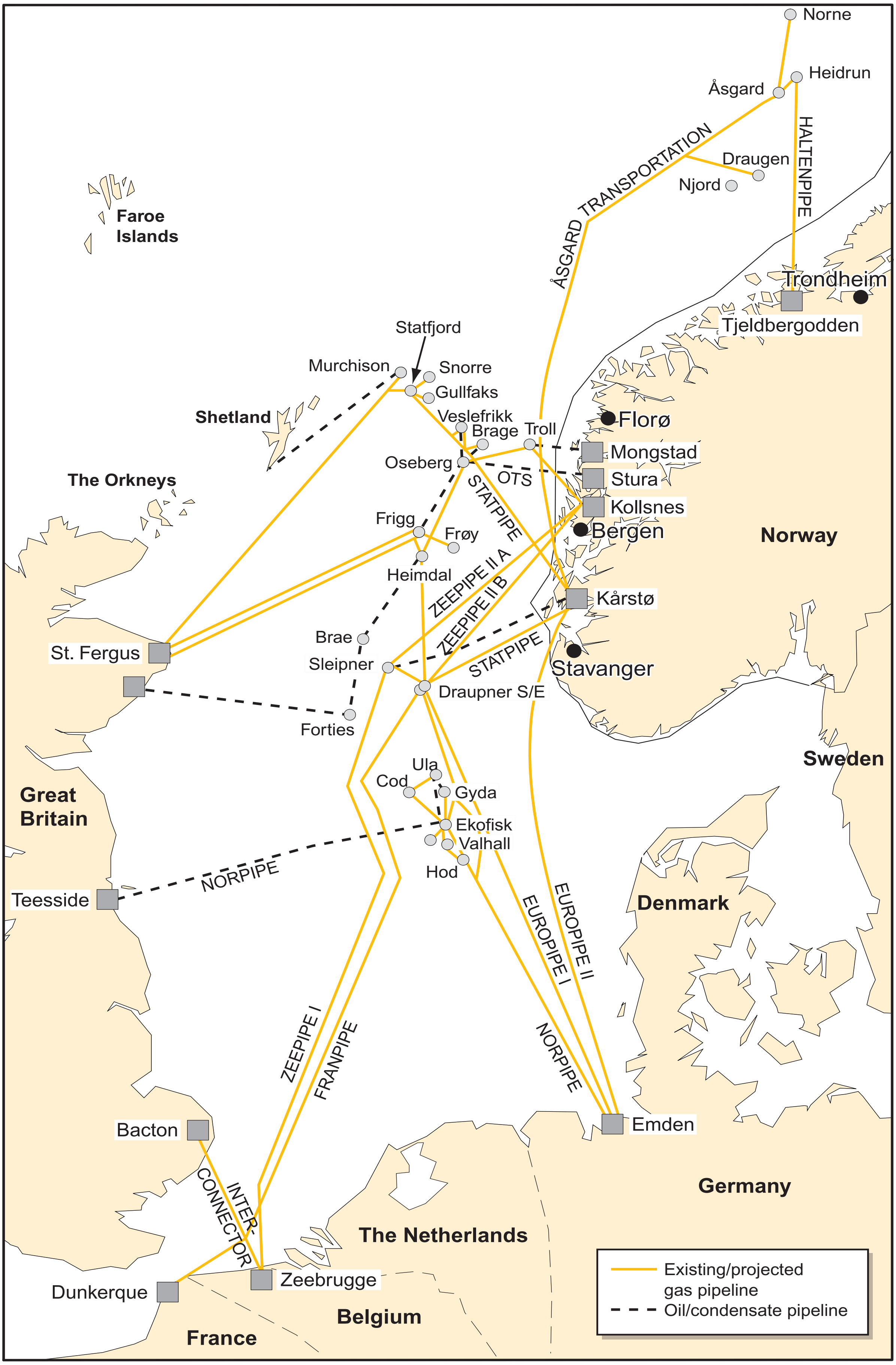
Den norske stats oljeselskap a.s.	100 %

The pipeline system for transportation of oil from the Ekofisk Center to Teesside in England is owned by Norpipe Oil A/S. Norpipe receives oil from the fields in the Ekofisk area and the nearby Valhall, Hod, Ula and Gyda fields. Several British fields also use the transportation system.

Norpipe Oil A/S is a corporation owned 50/50 by Statoil and the Phillips group. Phillips Petroleum Company Norway is operator of the pipeline.

The ownership structure for the facilities at the Teesside terminal are split between Norpipe A/S and the Phillips group, through the Norpipe Petroleum UK Ltd. and Norsea Pipeline Ltd. companies. Phillips Petroleum Company UK Ltd. is the operator of the facilities.

Figure 1.11.1 Transportation systems for oil and gas from Norwegian fields



1.11.2 PLANNED TRANSPORTATION SYSTEMS

The following section addresses transportation systems with submitted or approved plans for installation and operation.

Gas transportation

Norne Gas Transport
Ownership structure

Den norske stats oljeselskap a.s (SDFI: 55.00000%)	79.00000 %
Norsk Hydro Produksjon AS	8.10000 %
Norsk Agip AS	6.90000 %
Enterprise Oil Norwegian AS	6.00000 %

The Norne-Heidrun gas export system is a planned transportation system for rich gas. The transportation system is primarily constructed in order to trigger associated gas from the oil production on Norne and Heidrun respectively. Rich gas is sent from Norne-Heidrun gas export to processing in Kårstø via Åsgard Transport. The transportation system is scheduled for installation during the summer of 2000 and will be available for transporting gas from 1 October 2000. The technical concept entails a pipeline system with an outer diameter of 16" that starts at Norne, goes to Åsgard Transport, where it is tied in with a branch line to a dedicated T-connection on Åsgard Transport, and then on to Heidrun.

Heidrun Gas Transport
Ownership structure

Den norske stats oljeselskap a.s (SDFI: 65.00000%)	76.87500 %
Norske Conoco A/S	18.12500 %
Fortum Petroleum AS	5.00000 %

Heidrun Transport is the section of the Norne-Heidrun transportation system that goes from Heidrun to the T-connection on Åsgard Transport (see Norne Gas Transport).

Åsgard Transport
Ownership structure

Norsk Hydro Produksjon AS	2.60000 %
Mobil Development Norway AS	7.35000 %
Total Norge AS	7.65000 %
Norsk Agip AS	7.90000 %
Saga Petroleum ASA	9.00000 %
Den norske stats oljeselskap a.s (SDFI: 46.95000%)	60.50000 %
Fortum Petroleum AS	5.00000 %

Åsgard Transport is a 745-kilometer pipeline with an outer diameter of 42" for transportation of gas from Åsgard and other fields on Haltenbanken to Kårstø. The pipeline will have a capacity of 19 billion Sm^3 per year and the plan is to put the pipeline into operation on 1 October 2000.

Oseberg Gas Transport
Ownership structure

Den norske stats oljeselskap a.s (SDFI: 50.78379%)	64.78379 %
Elf Petroleum Norge AS	5.76959 %
Mobil Development Norway AS	4.32720 %
Norsk Hydro Produksjon AS	13.68186 %
Saga Petroleum ASA	8.55276 %
Total Norge AS	2.88480 %

Oseberg Gas Transport is a 108 kilometer pipeline with an outer diameter of 36" for transportation of gas from Oseberg to Statpipe via Heimdal. The pipeline will have a capacity of approximately 14.5 billion Sm^3 per year and the plan is to put the pipeline into operation on 1 October 2000. Norsk Hydro is the operator.

1.12 PROJECTS

1.12.1 COOPERATION PROJECTS

FORCE
FORCE (“Forum for Reservoir Characterization, Reservoir Engineering and Exploration Technology Co-operation”) is a cooperation forum on problems related to exploration and improved oil recovery. FORCE started in 1995 and, in 1998, was continued until the end of 2001. In the autumn of 1999, it was decided that the FIND Cooperation Forum would be continued within FORCE. As of 1 January 2000, the FORCE agreement was amended to include exploration. The ongoing FIND projects will be continued under the FORCE organization.

Due to acquisitions and mergers, FORCE currently has 20 members including the Norwegian Petroleum Directorate and the Research Council of Norway. Pelican, which was a FIND member, is now a new member of FORCE. All members are represented on the board, where Statoil holds the chairmanship. The secretariat is located in the Norwegian Petroleum Directorate.

The main goal of FORCE is to contribute to increasing oil recovery on the Norwegian continental shelf. The potential for improved oil recovery is large and, to some extent, time-critical. FORCE is also a forum for collaboration on issues related to new technology associated with the exploration phase that may be relevant for the Norwegian shelf. FORCE provides the companies with a forum in which to discuss important issues with each other, with the authorities and with representatives from the research and supplier industries. In their respective organizations, the FORCE members have broad expertise and experience that provide a unique opportunity for solving problems together or initiating cooperation projects with external suppliers. The participants in FORCE discuss and initiate research, development and demonstration of methods and tools that can contribute to future improved oil recovery and new/improved exploration technology. FORCE has established technical committees within basin and reservoir modeling, seismic methods, advanced wells and recovery processes.

1999 has seen a sharp decline in project activity level, but a high level of participation in seminars/workshops.

FORCE organized the following seminars/workshops in 1999: «Downhole/Subsea Processing», «WAG Injection, Field Experience», «Advanced Reservoir Monitoring», «Ocean Bottom Seismic», «Faults, fractures and reservoir flow» and «Rock Mechanics: Implications for Reservoir Characterization and Hydrocarbon Production”. The meetings in FORCE have been of high professional quality, and have contributed to improved understanding of challenges within the various fields. All of the FORCE events have been very well attended.

The following FIND projects have been continued or completed in 1999:

The “Evaluation of Well Results” project has consisted of reporting prognoses for drilling and results from drilling all of the exploration wells drilled since 1990. The purpose has been to analyze the difference between the prognoses for the hydrocarbon volume prior to drilling and the result after the drilling.

The purpose of the «Supergrid Project» has been to make seismic data more easily accessible for interpretation. Fourteen companies and the Norwegian Petroleum Directorate, which is also the project manager, participate in the project. It is expected that the project will be completed in the first quarter of 2000 with a complete integration of newly developed software in PetroBank.

The project “Basin Analysis and Applied Thermochronology on the Mid-Norwegian Shelf” (BAT) consists of members from ten oil companies, the Norwegian Petroleum Directorate, the Geological Survey of Norway (NGU) and the universities in Oslo and Bergen. The project will implement isotope-based dating of faults, sediments and rocks for analysis of origin, diagenesis and thrust history for the Mid-Norwegian shelf.

The project “The Effects of Drilling Mud Components on the Quality of Geological Data” was completed in 1999. The results were presented to the participants in a workshop. For more information, check the web site http://www.force.org.

FUN

FUN (*Forum for **F**orecasting and **Un**certainty Evaluation Related to Petroleum Production*) is a cooperation forum relating to problems within the areas of preparing prognoses and uncertainty evaluations for future oil and gas production. FUN was started in May 1997 and has 18 oil companies and the Norwegian Petroleum Directorate as members. The Ministry of Petroleum and Energy and OLF (Norwegian Oil Industry Association) are observers in the forum. The forum has a board with representatives from all of the members. The Norwegian Petroleum Directorate now holds the office of chairman, and the Norwegian Petroleum Directorate is also responsible for the secretariat.

The main objective of FUN is to develop better practice and methods with regard to estimating hydrocarbon resources, forecasting future production with associated emissions and discharges, uncertainty evaluations and decision processes. Two working groups have been set up. Working Group 1 is to focus on improved information and reporting routines among the companies and between the companies and the authorities. Working Group 1 shall also be the forum for changes in connection with reporting for the national budget. Working Group 2 is responsible inter alia for initiating and being a program committee for workshops and seminars for managers and technical personnel. In addition, projects will be initiated through this working group.

In 1999, FUN has been used actively in connection with the national budget reporting in order to discuss reporting changes. The forum has also been used for feedback to and from the operators. In 1999, FUN also initiated a project relating to best practice within the field of forecasting and decision-making under uncertainty. The goal of the project is that the best practice document shall include a historical overview of the current practice and recommend the best practice for:

- production forecasts and resource classification
- prognoses for costs including investment and operating costs
- forecasting energy balances and energy-related emissions/discharges
- aggregation of stochastic and deterministic prognoses with uncertainty
- decisions based on stochastic and deterministic prognoses

The initial phase of the best practice project has consisted of mapping current practice in the companies and the authorities. The first phase will be completed in the first quarter of 2000. Twelve oil companies, the Ministry of Petroleum and Energy and the Norwegian Petroleum Directorate participate in the project. FUN also initiated a project relating to the procedure for calculating environmental data for the revised national budget in which five oil companies participated.

For more information, check the web site http://www.fun-oil.org.

SAMBA

In recent years, the Norwegian Petroleum Directorate has accumulated expertise and experience with regard to the use of databases and analysis tools. This has provided great advantages for the Norwegian Petroleum Directorate in connection with production of reports and analyses and in the delivery of final reports with a high level of quality to customers. The SAMBA project has been established in order for the Norwegian Petroleum Directorate to maintain the advantage of having good, quality-controlled databases based on modern IT technology in the future as well.

SAMBA entails a systematization and integration of information that provides the Norwegian Petroleum Directorate with a better overview of the activities on the Norwegian shelf.

The project also emphasizes use of standards found in the market. POSC’s (Petrotechnical Open Software Cooperation) Epicentre data model is used in the data modeling.

The SAMBA project was started as a pilot project in 1996, and the first system modules were put into use by the Norwegian Petroleum Directorate in 1997. As of 1 January 2000, 95 per cent of the SAMBA project has been completed. The system consists of information on the modules: companies, production licences, agreement-based areas, fields, field sections, discoveries, deposits, resource estimates for deposits, profile collections, transportation and exploitation facilities as well as parts of transportation and exploitation facilities. The Prospects and Resource Estimate for Prospects modules will be completed in 2000.

SAMBA is an essential tool for the Norwegian Petroleum Directorate in connection with the national budget reporting to the Ministry of Petroleum and Energy. The entire resource accounting is now found in the database. Provisions have been made which mean that the data is easily accessible both for the ordinary end user and for an advanced user who wants to explore the database in more detail on his/her own in order to assemble and analyze the data.

DISKOS

The DISKOS project started as a collaboration between Saga Petroleum, Norsk Hydro, Statoil and the Norwegian Petroleum Directorate in 1993 for development and operation of a common database (the DISKOS database) for technical petroleum data. The project now includes a total of 15 oil companies as well as the Norwegian Petroleum Directorate that are linked together in a high-speed electronic network. The DISKOS database includes most of the processed 2D and 3D seismic from the Norwegian shelf.

Access to the data is governed by the rules and agreements for usage rights which the parties have entered into or which are stipulated in the Petroleum Act. A comprehensive access rights system in the DISKOS database prevents unauthorized end users from obtaining access to confidential data.

The DISKOS database also contains quality-controlled data from exploration wells. The Norwegian Petroleum Directorate delivers quality-controlled administrative data to the database on a weekly basis. This data describes production licences, blocks, fields, seismic navigation, well locations, pipelines, etc. The DISKOS database now contains more than 30 terabytes of data. After a decline in use of the database at the beginning of 1999, inter alia due to reduced exploration activity in the companies, the database has been used considerably at the end of 1999. The transition to 2000 did not entail any problems related to the operation of the DISKOS database.

The PetroBank software used in the DISKOS database has been upgraded in 1999 with new modules for production data and filing data. In addition, the well data module has been developed further with new functionality. These improvements now make it possible to file all relevant seismic data and well data readily accessible for the end users. As of 2000, the Norwegian Petroleum Directorate's production reporting system will be included in the DISKOS database. This will enable the companies to report production data directly to the DISKOS database and share reported data with the production partners using the database. Other countries are very interested in the Norwegian DISKOS concept and similar projects are now being established in several locations around the world.

The collaboration in the DISKOS group is headed by the Norwegian Petroleum Directorate. The costs of development and operation will be divided among the users of the system. The operation of the database itself has been outsourced to the company PetroData A/S.

1.12.2 PARTICIPATION IN RESEARCH AND DEVELOPMENT PROGRAMS

In 1999, the Norwegian Petroleum Directorate has been involved in several public research programs and forums for technology development.

Offshore 2010

Offshore 2010 is a research program for user-controlled research and development in the petroleum sector. The program is administered by the Industry and Energy Section (IE) in the Research Council of Norway (NFR). The Norwegian Petroleum Directorate is a member of the board of Offshore 2010.

Petroforsk

Petroforsk is a research program for fundamental petroleum research. The program is organized by the Science and Technology Section (NT) in the NFR. The Norwegian Petroleum Directorate is a member of the program board of Petroforsk.

Petropol

Petropol is a research program that addresses internationalization and adjustment - new challenges for the Norwegian petroleum industry. The program is administered by the Cultural and Social Section (KS) in the NFR. The Norwegian Petroleum Directorate is a member of the program board of Petropol.

CORD

CORD is a forum where the oil industry and the research communities meet to discuss, define and initiate cost-effective production development through cooperation in R&D projects. The Research Council of Norway is responsible for administrative coordination of the program and SINTEF has the secretariat. The Norwegian Petroleum Directorate is an observer on CORD's board of directors.

Center for Operations and Maintenance

The Center for Operations and Maintenance is a foundation that addresses development of expertise and R&D projects within operations and maintenance, both for the petroleum industry and for other industries. Stavanger College (HiS) is responsible for the technical aspects and the Norwegian Petroleum Directorate participates in the foundation's technical council.

DEMO 2000

Project-focused technological development within the petroleum sector was initiated by a grant from the Ministry of Petroleum and Energy in 1999. The Norwegian Petroleum Directorate is an observer on the DEMO 2000 board of directors.

2.1 INTRODUCTION

The Norwegian Petroleum Directorate's performance of its administrative duties is based on a comprehensive administration of safety, working environment, health and the external environment. The Norwegian Petroleum Directorate has a coordinating role in relation to other public authorities that have independent supervisory responsibility in this area. Furthermore, the Directorate draws upon expert assistance from other departments in areas where it has no expertise of its own.

Administration of safety and the working environment is based on the principle of supervision of the industry's control over its own activities. This assumes that regulations are designed and supervision is implemented in a way that supports the participants' responsibility to carry out prudent operations in accordance with the formal framework for the petroleum activities.

Therefore, supervision of regulatory compliance is primarily aimed at management systems and decision processes that have significance for safety and the working environment. Through its supervision activities, the Norwegian Petroleum Directorate seeks to stimulate improvement processes in the companies, as well as to evaluate the companies' ability to manage their own activities in accordance with the requirements of the authorities and of the companies themselves.

The Norwegian Petroleum Directorate aims at providing continuity, systematism and a long-term perspective in the supervision of safety and the working environment. In order to achieve this, the Directorate seeks to form an image of the development trends in this area over time, both in the industry as a whole and in the individual companies. In areas where the development is not as expected, the Norwegian Petroleum Directorate can then prioritize measures vis-à-vis the industry as a whole, towards the licensees in a production licence, towards an individual operating company, or towards other participants. The Directorate also provides advice to the supervising ministries with regard to the overarching framework for the activities.

2.2 OVERALL EVALUATION OF DEVELOPMENTS IN THE AREAS OF SAFETY AND WORKING ENVIRONMENT

The past decade has been characterized by a growing demand for ever-greater cost reductions in respect of investments and in operations. The decline in the price of oil at the end of 1998 and the beginning of 1999 reinforced these demands. The authorities have also taken a positive view of measures designed to increase competitiveness, and have taken initiatives vis-à-vis the industry, for example through the so-called NORSOK processes. In this connection, the authorities had a clear precondition to the effect that the established levels of health, environment and safety would not be reduced as a consequence of the efforts to reduce costs.

Several independent observations and evaluations indicate that the overall risk level is starting to rise, and that this negative trend could characterize the next decade. This development is a source of concern for the authorities, who now face the dilemma of striking a balance between setting ambitious goals for profitability and maintaining demands for responsible operations as concern health, safety and the environment.

The industry has implemented significant organizational change processes, which have proven to lead to unclear responsibilities in certain important areas. At the same time, the average age of the offshore installations is increasing, with the associated maintenance problems this entails. In many cases, the demands on profitability in the development of marginal fields also lead to challenges with regard to health, safety and environmental requirements.

Even though the price of oil in 1999 has been at a considerably higher level than in 1998, the companies have continued their strong commitment to cost reductions. The companies evaluate cost levels in comparison with each other, with the result that all of the companies attempt to reduce costs to an average that is ever lower.

This trend is reflected inter alia in:

- merging of companies
- outsourcing
- new organization forms
- reduction of operating costs, including staff reductions
- increased use of integrated IT management systems

All of these measures contain elements that could yield negative effects as regards safety and the working environment, either directly or indirectly, if the processes leading up to the various decisions are not properly managed. In its supervision of some of the change processes, the Norwegian Petroleum Directorate has observed that there often seems to be excessive focus on the actual goal of the process, so that the process itself does not receive sufficient attention.

At the same time, the Norwegian Petroleum Directorate has experienced through its supervision that most of the companies have multiple change processes underway simultaneously, or that the processes follow one after another at an increasing pace. Examples of such simultaneous change processes may be modification of existing facilities or introduction of new technology, organizational changes, changes in management systems or operations and maintenance strategy. In many cases, it appears that these various change processes are not coordinated in relation to each other, and often suffer from insufficient evaluations of the overall consequences on safety and the working environment.

1999 has also been marked by several mergers of companies. Mergers bring changes in management systems, organization and staffing, either as a consequence of the establishment of a new organization out of the merger companies, or that operator tasks are transferred from one company to another. This results in substantial challenges, as in every other change process. In addition, personnel from different corporate cultures must learn how to function together as a new unit.

Reduction in operating costs

The companies' endeavors to reduce operating costs can create challenges with regard to safety and the working environment. This primarily applies to existing installations, because these have been designed and built with a given need for manning, maintenance, emergency preparedness, etc. The efforts to minimize future operating costs may also prove to be difficult with regard to new installations, as assumptions and preconditions for operations with low manning levels may prove to be difficult to attain in practice.

The regulations do not stipulate specific requirements as to how the activities shall be organized, nor do they indicate specific manning levels. Therefore, reorganization including staff reductions with a view towards optimizing manning does not in itself constitute a breach of the regulations relating to safety and the working environment, insofar as such processes are carried out in accordance with regulatory requirements. Such requirements include employee participation and assessment of the consequences on safety and the working environment. Otherwise, there will only be a formal basis for intervention if the changes result in activities that are not carried out in a prudent manner.

Such effects may have a relatively long time perspective, and may also take a long time to rectify, if they are allowed to occur. Therefore, it would be too defensive of the Directorate to await a negative development before planning measures that can counteract such undesirable development. As in 1998, the Norwegian Petroleum Directorate has once again found this to be a reason for prioritizing supervision of how the operating companies managed organizational changes in 1999. Careful monitoring of this area will also be included when planning supervisory activities in 2000.

The companies largely plan for manning levels both on land and offshore that assume "normal" operations, in other words, an operating situation where there are no technical or organizational changes, major maintenance tasks, etc. Experience, however, indicates that this normal state rarely occurs in practice.

The Directorate fears that organizational changes and downsizing will lead to a loss of valuable competence which may take a long time to rebuild. If the current activity level is to be maintained in the years to come, there will be a danger that a shortage of capacity and competence will lead to a significant setback in safety and working environment developments in the petroleum activities on the Norwegian shelf.

2.3 SUPERVISION ACTIVITIES

Scope of the supervision

The Norwegian Petroleum Directorate expends a considerable amount of its personnel resources on supervision of how the responsible companies look after their duties regarding regulatory requirements. This use of resources is subject to reimbursement from the companies that are the objects of such supervision according to the *Regulations relating to refunding of expenses in connection with regulatory supervision of safety, working environment and resource management in the petroleum activities.* The reimbursable supervision includes the Directorate's activities relating to:

- planning of the supervision
- processing applications for production licenses
- processing plans for development and operation (PDO) and plans for installation and operation (PIO)
- processing applications for consent
- system audits and verifications, incl. preparation and completion work, travel time, etc.
- participation in status meetings with the projects
- participation in committee meetings with the licensees
- follow-up of hazardous and accident situations
- emergency preparedness exercises
- processing reports relating to incidents, etc.
- processing applications for exemptions from the regulations
- individual decisions and other use of measures
- meetings with relevant governmental departments
- management and administration

In 1999, the reimbursable part of the Directorate's supervision work amounted to 51,202 man-hours, compared with 57,793 hours in 1998. The decline is due to increased use of resources in the work to revise the regulations for safety and working environment, which is now in its final phase. However, the supervision has largely been performed in accordance with the work plan for 1999. This plan was prepared with strict prioritization of the most essential supervision in order to enable completion of the regulatory work while still carrying out an appropriate level of supervision.

Experience and observations from supervision of fields in operation

Experiences from the Norwegian Petroleum Directorate's supervision of the operators' management of organizational changes related to fields in the operations phase can be summarized in the following main points:

- The companies continue to underestimate the complexity of the change processes. The focus is on the goal, and only to a limited extent on the change processes themselves and the safety and working environment challenges they represent.
- Evaluation of the consequences of the change plans is often inadequate. There is particularly a lack of a comprehensive summary of the overall consequences when there are multiple change processes running at the same time.
- In connection with the introduction of integrated IT management systems, the need for training and the work associated with necessary adaptations between the organization and the system, and between the various systems, is often underestimated.
- There is little follow-up of suppositions and assumptions after the changes are implemented.
- Changes that have been implemented in the operations

and support organizations on land have proven to have greater than expected consequences in relation to operations and maintenance on the installations.
- Tight manning levels mean that employees have a hard time keeping up with their work load. This, together with poor communication and preconditions that are not fulfilled, easily leads to a frustrated and dejected atmosphere among the employees.
- The Directorate has noted cases of deficient participation by the employees' representatives in the early stage of decision processes, and a lack of clarity regarding which issues are to be considered in accordance with the provisions of the Working Environment Act, and which issues are to be considered in accordance with the main agreement.

In spite of these observations, the Norwegian Petroleum Directorate would point out that the changes also provide openings for interesting new organization forms, as well as opportunities for developing the individual employee's competence and influence in his/her own working situation. Over the long term, this can provide both the companies and the individual employee with greater flexibility and the ability to adapt to changed framework conditions. Changes in organization forms in the petroleum activities also entail new conditions and challenges for the organization of the safety delegate service. This will require a review of the regulations in order to ensure that the safety delegate organization can meet the new situation and continue to contribute to maintaining a prudent safety level and working environment.

Experience and observations from supervision of new development projects

New development solutions with operations based on low levels of manning, new organization forms and changes in the division of tasks between the installation and the organization on land place greater demands on systematic analysis of the work tasks in order to determine the need for competence and manning, and as a basis for recruiting and training plans.

In 1999, the Norwegian Petroleum Directorate has continued to aim supervision activities at new operations organizations in order to gain experience with these new forms. There has been a positive trend in the use and understanding of analyses, but there is still a need for improved clarification of assumptions and conditions that are used as a basis. The purpose of this is to facilitate follow-up of whether such assumptions and conditions have been safeguarded when it comes to the operations phase.

Experiences from the Norwegian Petroleum Directorate's supervision of the operators' management of organizational changes related to new development projects can be summarized in the following main points:
- On the whole, the companies plan for tight manning levels using matrix organization, multi-disciplinary organization, "trouble-shooting teams", and systems whereby more functions are handled by the organization on land.
- The manning plan is fixed at an early stage, often before realistic activity analyses have been performed.
- Manning studies in the project phase are of varying quality, but there is a positive trend towards increased use of a systematic approach.
- Assumptions and conditions that are used a basis are not prepared with a view towards follow-up in the operations phase.
- Ambitious new maintenance strategies have proven to be difficult to live up to.
- IT provides new opportunities for efficient organization, but there has been little illumination of the consequences on safety and the working environment. The anticipated efficiency gains may be exaggerated.
- It has proven difficult for some employees to become comfortable with having responsibility for planning and control of their own work, without the possibility of obtaining professional support from their immediate supervisor.

A common feature of the development outlined for both the development and operations phases has been that they are largely based on expectations, rather than on experience. Untried organization forms, new cooperation forms between operating companies and between operators and contractors, while simultaneously testing new technology, demands a determined effort in the authorities' overall supervision of safety and the working environment in the activities.

Supervision of mobile drilling installations

The main conclusions from supervision of mobile drilling installations is that there is still some weakness in the management of maintenance activities, particularly as regards installations that are approaching their design lifetime. Experience from the supervision indicates that there is not much prioritization of the maintenance tasks on the part of the companies. The Norwegian Petroleum Directorate believes that improved prioritization of the work tasks would make it possible to maintain equipment that is critical to safety in accordance with the preconditions.

In recent years, the Norwegian Petroleum Directorate has increased the scope of the supervision activities aimed directly at owners of mobile installations, primarily drilling rigs. In several cases, the supervision has also uncovered substantial shortcomings in the ship owner' regulatory competence. The visible effect of this is that an alarmingly high level of deviations with direct impact on health, environment and safety has been discovered on several drilling rigs.

These deviations have, in previous years, largely been discovered through the Norwegian Petroleum Directorate's supervision activities, or by the operator that has a contract with the ship owner. Only to a lesser extent have these deviations been discovered by the ship owner's own organization.

The supervision in 1999, however, has yielded indications that this condition may, to some extent, be ascribed to “cultural” conditions in the form of a lack of tradition of openness regarding deviations, and thus the understanding of how a good mapping of deviations contributes to improvements. There are now signs that indicate that this is starting to improve.

In one case, the Norwegian Petroleum Directorate issued an order after supervision of a mobile drilling rig that subsequently led to the operating company temporarily suspending drilling activities with this installation. The circumstances that formed the basis for the Directorate’s notification of order were related to parts of both the operator’s and the ship owner’s management systems, but also technical conditions on the installation. Among other things, this was related to systems for detecting and fighting fires, lifting devices/equipment and drilling equipment.

Supervision of how the industry handled IT problems associated with Year 2000

The Norwegian Petroleum Directorate has worked on Year 2000 problems since the end of 1997. The Directorate has followed up the operators’ work through letters, surveys, meetings and audits, and has particularly been concerned with the potential effects of problems associated with the transition to Year 2000 as regards

- the safety of people and the environment,
- delivery security for gas to recipients on the Continent,
- regularity of oil production.

The operators set up a cooperation forum, Y2k Oil and Gas Forum, to exchange information and experience, and to create understanding for the importance of prioritizing this unique problem. The Norwegian Petroleum Directorate participated as an observer in the monthly meetings of this forum.

In 1998 the Norwegian Petroleum Directorate took the initiative for the performance of an overall risk and vulnerability analysis for gas deliveries from the Norwegian shelf in accordance with the government’s follow-up plan for the Year 2000 problem. The analysis was performed by key gas suppliers on the Norwegian shelf. In 1999, the same companies were asked to develop coordinated preparedness to safeguard deliveries in connection with the millenium.

Meetings were held with relevant bodies among the German, French, Belgian and British authorities. In accordance with the agreements entered into by and among the countries, the Norwegian Petroleum Directorate has provided information regarding the work on the Norwegian side in connection with the transition to the Year 2000, with chief emphasis on delivery security for gas to the recipient countries.

The responsible ministries have been informed about the Directorate’s work on the Year 2000 problem through quarterly reports and meetings.

In spite of the tremendous efforts to correct errors, the majority of the companies experienced various unforeseen events. None of these were critical in safety terms, and the preparedness functioned well. This meant that production on all installations on the Norwegian shelf continued as normal.

A lot of equipment was replaced during the preparations for the new millennium. There was also a substantial refurbishing of software and fortifying of telecommunications systems. All together, these measures have contributed to a modernization that will have a positive effect on both safety and efficiency in the operations.

Even though the operators worked very hard to correct Year 2000 errors, there was no way to be certain that all errors had been discovered prior to the turn of the millennium. Therefore, establishing preparedness for potential courses of events resulting from such errors was a key issue in 1999. The special preparedness that the operating companies were asked to implement included preparedness measures relating to safety, the environment and material assets, including delivery security at the turn of the millennium.

These preparations also included mapping which systems and other participants the individual companies are dependent on, as well as the consequences that various types of problems could entail. This work has provided insight into how robust the systems are in relation to various types of errors that could arise. This knowledge is clearly also valuable after the turn of the millennium.

2.4 REGULATORY DEVELOPMENT

Development of new regulatory structure

In 1999, the Norwegian Petroleum Directorate, together with the Norwegian Pollution Control Authority and the Norwegian Board of Health, cooperated with the industry to continue the comprehensive work associated with revising the regulations in the areas of safety, working environment, health and the external environment. The work was started in 1997 with a point of departure that included a new Petroleum Act with associated regulations stipulated by Royal Decree which entered into force on 1 July 1997, as well as underlying regulations.

A decision has been made to the effect that the future underlying shelf regulations shall consist of four regulations for the following areas:

- management
- operations
- technology
- duty of information

The four new regulations will be established and enforced by the three authorities jointly, and in accordance with the principles laid down in the system for coordinated supervision on the shelf.

The three-part regulatory forum “External Reference Group for Regulatory Development” (ERR) gave its general endorsement of the structure of the new regulations in 1998. Through ERR, the concerned parties are involved in the work of developing the contents of the four new regulations. The Norwegian Petroleum Directorate has had good experience with this from previous regulatory development efforts.

The goal of the revision work is not to tighten the requirements for the activities, but to continue the current regulation within the framework of a new regulatory structure. In the opinion of the Directorate, such a change will make the regulations more accessible, and will provide the supervisory authorities with more comprehensive and efficient control instruments. The purpose is also to facilitate a greater degree of utilization of recognized industry standards, increase predictability when applying the regulations to mobile installations, to provide a more comprehensive and multidisciplinary approach to various fields of responsibility, and to better adapt the regulations to the structure of the EEA regulations.

At the same time, work has continued on the draft for a new Royal Decree, or the so-called main regulations, that are to apply to this area. The working drafts were subjected to internal consultation in the autumn of 1999. Simultaneously, the industry was also asked to comment on the drafts. The comments proved to be extensive and, in consultation with the Ministry of Local Government and Regional Development, it was decided that the deadline for submitting the documents to the Ministry with a request for approval to send the documents out for external consultation should be postponed until the end of January 2000.

As a part of this work, there has also been continuous follow-up of relevant standardization work, in part through direct participation in the standardization work, and in part through formal consultation rounds.

The timeframe for the work indicates that the new regulations should enter into force at the turn of the year 2000/2001.

Annual updates of the regulations

Annual updating of the regulations has also taken place in 1999. The changes, all of which were minor, took effect as from 1 June 1999.

Regulations relating to pressure equipment

On 9 June 1999, the Norwegian Petroleum Directorate established new regulations relating to pressure equipment in the petroleum activities. These regulations incorporate the EU Directive relating to pressure equipment in the shelf regulations. This directive contains a transitional arrangement until 29 May 2002, which means that the current regulations in this area can be used in the petroleum activities on the Norwegian shelf up to this date.

References to national and international industry standards in the shelf regulations

The aim of the Norwegian Petroleum Directorate is that the overall regulations for safety and the working environment in the petroleum activities shall be formulated in the most rational way possible, including references to recognized national and international industry standards in the regulations to the greatest extent possible. In connection with the annual revisions, the Directorate has had a dialogue with the Norwegian Technology Standards Institution/ NORSOK with a view towards incorporating references to NORSOK standards in the regulations.

In 1999, there has also been a continuous follow-up of international standardization work under the direction of ISO/IEC and CEN/CENELEC for those areas that border on the regulations.

2.5 GUIDANCE AND INFORMATION

The Norwegian Petroleum Directorate aims at ensuring that all parties affected by the exercise of administration shall be able to obtain the best possible guidance with regard to interpretation and understanding of regulations and the supervision system. The Directorate views this part of the activities as a significant contribution to the endeavors to attain the best possible compliance with the intentions and requirements of the regulations. As for the industry, the guidance activities can contribute to avoiding unnecessary costs as a consequence of misunderstandings and "over-interpretation" of the regulations' requirements for safety and working environment.

In 1999, a significant part of the guidance activities were once again oriented towards design and construction of mobile installations "on speculation"; in other words, installations where there is no application for consent from an operating company regarding a specific application on the Norwegian shelf.

Mobile installations are normally built at construction yards that have most of their experience and knowledge from shipbuilding, and are therefore familiar with maritime regulations. The petroleum regulations have a different manner of approach to safety and working environment issues, which particularly foreign shipyards have difficulty relating to. Therefore, there is a great need for both a general dissemination of knowledge regarding the principles in the regulations and the supervision, and for clarifications of a more specific nature. This need appears to be pervasive for all of the participants in this industry.

Acknowledgement of compliance (AoC) for mobile units

In 1998, the Ministry of Local Government and Regional Development asked the Norwegian Petroleum Directorate to commence work on developing a system for a form of «advance statement», later called «acknowledgement of compliance» for mobile units. The background for this initiative was inter alia a longstanding desire on the part of the shipping industry that such a system should be developed.

The intention of the system is that it shall contribute to providing the owners of mobile installations that have not entered into contracts for use on the Norwegian shelf with improved predictability concerning the installation's suitability in relation to the requirements of the petroleum regulations. Another goal is to streamline the work processes related to verifications and consideration of applications both in the industry and on the part of the authorities. The Norwegian Petroleum Directorate also expects a positive impact on the health, environment and safety management of mobile drilling rigs in that the system will contribute to placing the responsibility for such management more on the rig owner, where it belongs.

In order to develop such a system, a working group led by the Norwegian Petroleum Directorate was set up in the autumn of 1998. Other participants in the group are the Norwegian Shipowners' Association, the Norwegian Oil Industry Association, the Norwegian Federation of Trade Unions, the Federation of Oil Workers' Trade Union, the Norwegian Maritime Directorate, Det norske Veritas, the Federation of Norwegian Engineering Industries and the Norwegian Licensees' Association.

The working group decided in 1999 that the system would be restricted to apply to mobile drilling rigs. However, the system will be subject to an evaluation after about two years. In this connection, it may also be relevant to consider a possible expansion of the system to also apply to other types of mobile installations.

The main emphasis of the work in 1999 has been on preparation of the technical basis for evaluation. This work has been performed by Det norske Veritas. At the same time, the Norwegian Petroleum Directorate has cooperated with the Norwegian Maritime Directorate to develop guidelines for applications for AoCs under this scheme.

The plan is for the system to become effective in the last half of 2000.

2.6 ACCIDENTS INVOLVING PERSONAL INJURIES

The Norwegian Petroleum Directorate receives continuous reports regarding personal injuries that occur on installations involved in petroleum activities on the Norwegian shelf. Fatalities, serious personal injuries and other serious incidents must be reported to the Directorate immediately. In addition to this immediate notification, all personal injuries that require medical treatment or which lead to absence during the following 12-hour shift, shall be reported to the Norwegian Petroleum Directorate using a special form. The form is also used to report industrial accidents to the National Insurance Administration. The information from these forms is recorded in the Directorate's register for personal injuries in the petroleum activities, and inter alia provides a basis for the statistics provided in this annual report. The main features are cited in the annual report while more detailed tables and figures are published on the Norwegian Petroleum Directorate's web pages.

In 1999, the Norwegian Petroleum Directorate received reports of 884 personal injuries related to the petroleum activities on the Norwegian shelf. Of these, 43 were classified as off-duty injuries and 40 as first aid injuries. These injuries are not included in the statistical presentations.

There was one fatality on the shelf in 1999. A roughneck that was hoisted up in a manrider to free a drill pipe died of injuries he received after being crushed between the upper pipe handling arm and a drill pipe. The circumstances are described in more detail in a safety notice sent out by the Norwegian Petroleum Directorate after this accident. This was the first fatality within the Norwegian Petroleum Directorate's sphere of responsibility on the shelf since 1995. During the past ten years, a total of nine people have died in industrial accidents in the offshore petroleum activities. It is an absolute goal, both for the authorities and for the companies that fatal accidents should not occur.

Figure 2.6.1 shows the frequency of injuries within the main activities on permanent installations on the Norwegian shelf for a period of ten years up to 1999. The overall injury frequency exhibits minor changes during the period, while the variations are somewhat greater for the various main activities. Drilling and well operations are the only activities that exhibit a clear declining trend in injury frequ-

Figure 2.6.1
Personal injury frequency on permanently located installations

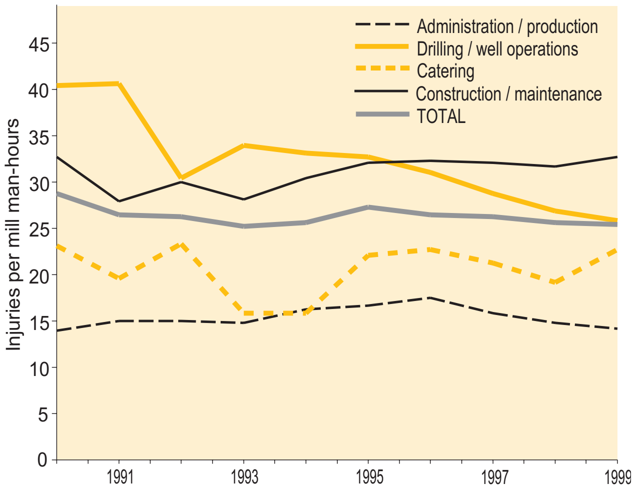
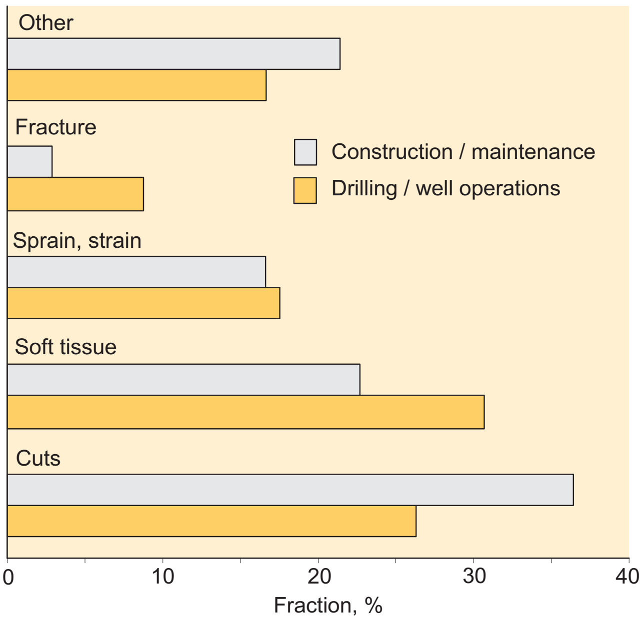


Figure 2.6.2
Distribution of injuries on permanently located installations 1999.



ency during the ten-year period. This personnel group also had the greatest reduction in injury frequency over the past year. Thus in 1999, construction and maintenance activities constitute the personnel group that is most vulnerable to injuries. This is the same trend as last year. This group also accounts for the highest number of personnel on permanent installations or approximately 44 per cent of the man-hours in 1999.

Figure 2.6.2 compares the relative distribution of the most common types of injuries associated with drilling and well operations with comparable figures for construction and maintenance. Soft tissue injuries were most common in drilling and well operations, often caused when the injured person was struck or crushed by heavy or moving equipment. Cuts and scrapes are the most common types of injuries in construction and maintenance. Most of these injuries are caused by contact with sharp components or structural elements. Proportionately speaking, there were more fracture injuries associated with drilling and well operations than for construction and maintenance activities. This could be an indication that drilling and well personnel are more vulnerable to serious injuries.

Figure 2.6.3 shows that contractor employees on permanent installations are more vulnerable to injuries than operating company personnel. For 1999, this difference applies to all of the main groups of personnel. In particular, the injury frequency for catering personnel employed by contractors has increased by 8.5 injuries per million man-hours from 1998 to 1999. There has also been a relatively large increase in the injury frequency of 4.2 injuries per million man-hours for operating company personnel in the field of construction and maintenance. Nevertheless, the injury frequency here is far lower than for comparable personnel employed by contractors. On mobile installations there will normally be just one or a few representatives from the operating companies. Only one person employed by an operating company was reported injured on mobile installations in 1999.

Figure 2.6.3
Personal injury rate by operators and contractors on permanently located installations - 1999

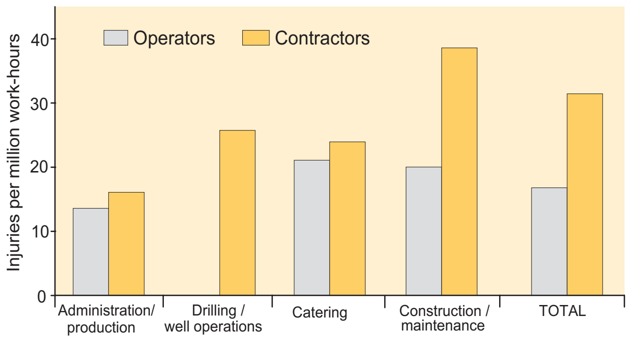
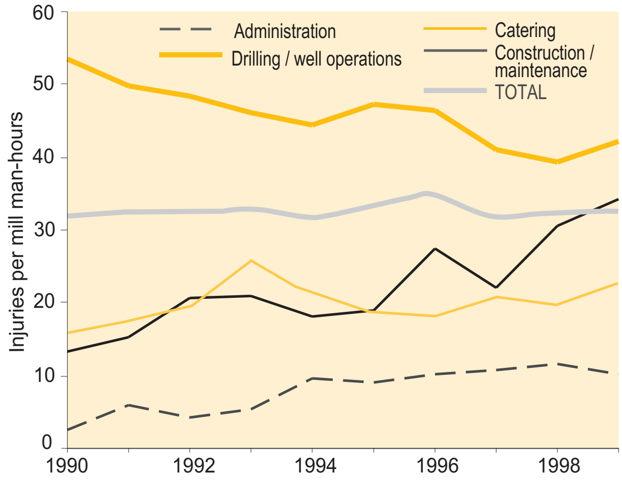


Figure 2.6.4 shows the injury frequency for the main

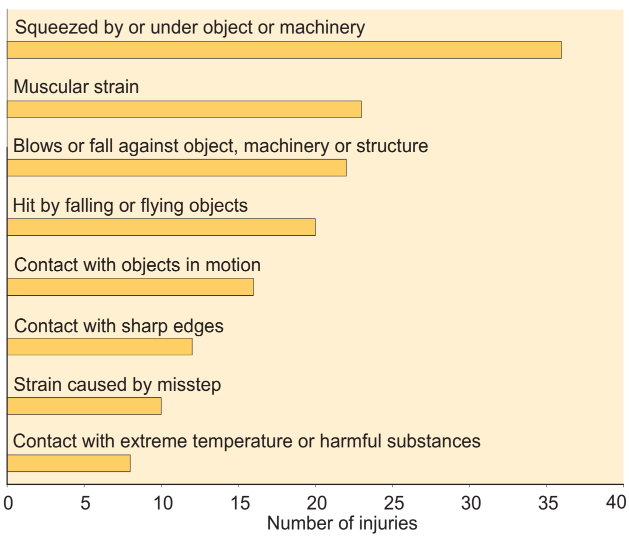
Figure 2.6.4
Personal injury frequency on mobile installations



activities on mobile installations on the Norwegian shelf for the ten-year period up to 1999. In the same manner as for permanent installations, the overall injury frequency exhibits only minor changes during the period. On mobile installations, all personnel groups with the exception of administration have shown an increase in injury frequency from 1998 to 1999. Even though the operations/maintenance group has exhibited a marked increase in injury frequency in the past three years, drilling and well operations are still the most vulnerable group on mobile installations. In 1999, drilling and well operations accounted for approximately 48 per cent of the man-hours on mobile installations, as compared with 57 per cent in 1998.

Figure 2.6.5 illustrates a rough distribution of the manner in which drilling and well operations personnel on mobile installations were injured in 1999. The most common type of injury is various forms of crushing injuries. These incidents are most often triggered by unintentional start-up or movement of heavy equipment or material on the drill floor, either caused by the injured person himself or by

Figure 2.6.5
Cause of injury for drilling and well operations on mobile installations - 1999



others. Overstraining occurs most often in connection with lifting heavy equipment. Of the injuries within drilling and well operations, 83 per cent occurred in the drilling area and 42 per cent on the drill floor. More than 53 per cent of accidents resulting in injuries entailing absence or more serious consequences occur on the drill floor.

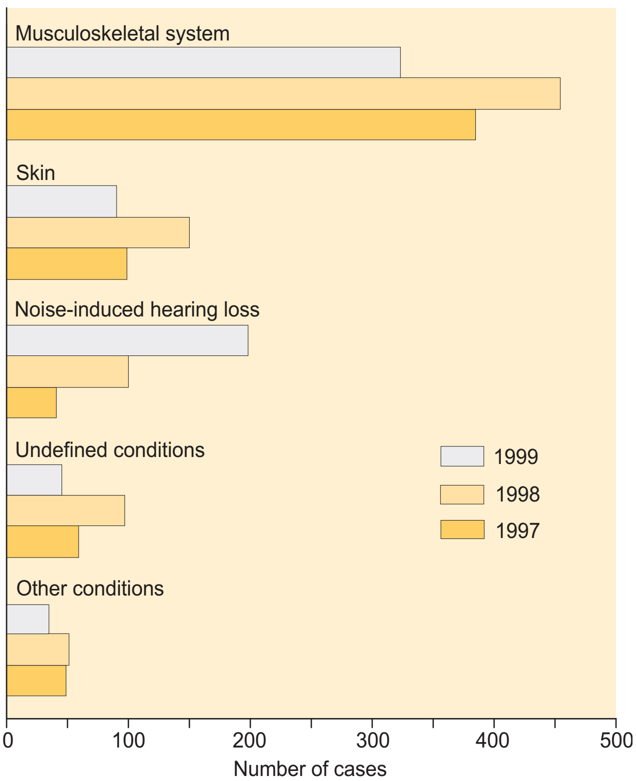
Detailed tables and information regarding personal injuries may be found on the Norwegian Petroleum Directorate's web pages.

2.7 WORK-RELATED DISEASES

The incidence of work-related diseases can be an indicator of the quality of the working environment. During recent years, the Norwegian Petroleum Directorate has worked towards the goal of having the companies establish this as a working environment indicator and make active use of it in their preventive safety and environmental work. Therefore, it is a positive trend that more companies are beginning to compare the frequency of work-related diseases with personal injury frequency.

691 notifications of work-related disease were received by the Directorate in 1999, divided between 235 for operator employees and 471 for contractor employees. This represents a 17 per cent decrease in the number of notifications as compared with 1998, giving a notification frequency of 23.5 incidents per million man-hours. The decrease may be due to the effects of preventive work, although some of the decline is probably the result of the fact that there were fewer man-years worked on the shelf

Figure 2.7.1
Distribution of work-related diseases on diagnosis groups 1997-99



last year. In order to contribute to the companies continuing to focus on work-related diseases, the Norwegian Petroleum Directorate will carry out supervision aimed at reporting and further follow-up of new cases, both for operating companies and contractors.

If we disregard hearing injuries due to noise (198 incidents), the frequency of other diseases is 23.8 cases per million man-hours. This is considerably higher than what has been reported for land-based industry. There may nevertheless still be a certain amount of under-reporting, as there are still few reports received from some companies that have many employees on the shelf. Therefore, the Norwegian Petroleum Directorate will continue its efforts to achieve a more uniform reporting practice through contact with the companies.

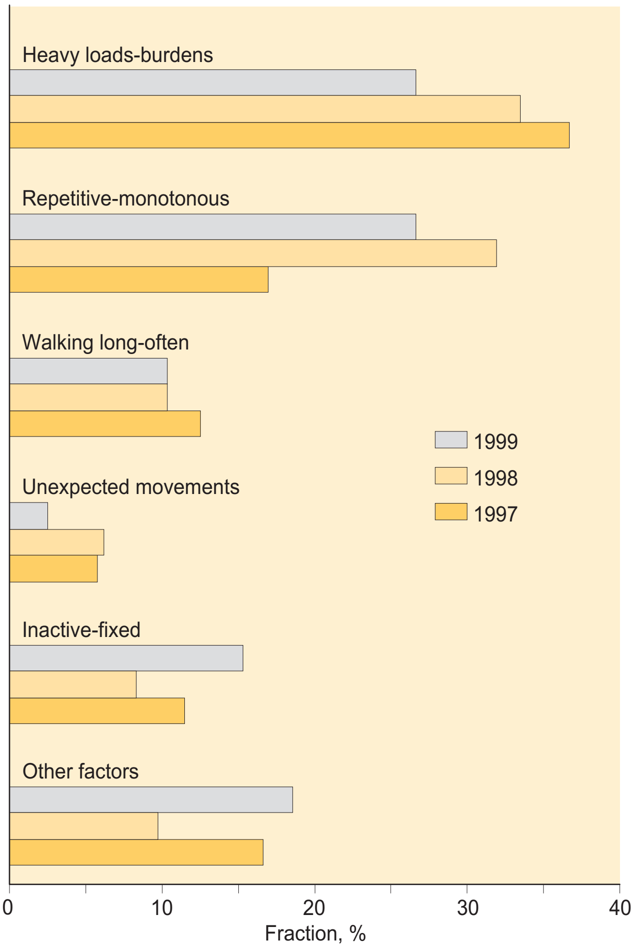
The form for reporting work-related diseases has been changed in order to have a clearer picture of the main features of the material, and to achieve a clearer correspondence between injuries and work activity. Figure 2.7.1 shows the distribution of some of the main groups of work-related diseases registered in the period 1997-1999. As previously, noise-induced hearing loss has been included and split out as a separate group. This is because the reporting requirement for this type of disease was changed in 1997, in accordance with the regulations of the Directorate of Labour Inspection. While these incidents were previously to be reported in summary, they must now be reported individually. This will provide a better opportunity to follow up individual incidents. Even though there is a significant increase in reported incidents of noise-induced hearing loss, from 100 in 1998 to 198 last year, there is still some uncertainty as to whether all new cases have been reported.

As previously, the picture is dominated by muscular and skeletal disorders (including disorders of the connective tissues). These types of disorders are normally referred to as repetitive strain injuries. They include back disorders, tendinitis and various forms of muscular pain. There has been a significant decrease in the number of such incidents compared with the previous year, and the proportion of such incidents has decreased from 54 per cent of the reported incidents in 1998 to 47 per cent in 1999. In spite of this decrease, the figures remain high, and show that it is important to direct efforts towards preventive work in relation to these types of ailments. Not surprisingly, the stated causes of the cases in this group are largely manual labor within the areas of drilling, maintenance and catering.

The exposures, which are listed as the causes of these repetitive strain injuries, are summarized in Figure 2.7.2. This figure includes data for the last three years.

The figure shows that handling of heavy loads and heavy lifts were listed as the most important causes of diseases in the muscular and skeletal systems in 1999. This proportion was 7 per cent lower compared with the previous year. Another important cause of this type of injury was repetitive, monotonous work, although the percentage of this type of work listed as a causal factor was reduced compared with 1998. Both heavy work and repetitive monotonous work are listed as causes of inter alia tendinitis and muscle pain.

Figure 2.7.2
Exposure factors - musculoskeletal conditions



The proportion of cases of degenerative changes in knees and hips attributed to extensive walking on hard surfaces is relatively high, but unchanged compared with the previous year. Heavy lifts, sudden movements and inactive/ stationary work have often resulted in back problems (lumbago/ sciatica). Difficult access, which means that work must be performed in a crawling position or while kneeling, is another frequent cause of various knee ailments. This category is included in the group "Other" and, among other things, constitutes an important reason for the increase observed in 1999.

Another large diagnosis group is skin conditions, but the number and the proportion of incidents in this group declined in relation to 1998. Just under half of the cases relate to eczema on the hands after contact with oil-based drilling mud. Some cases can also be attributed to other organic compounds, while epoxy is listed as the cause of four cases of contact eczema (down from six cases the year before) and one case of general allergic reaction. In 1999, there were no reports of isocyanates as the cause of eczema, while four such cases were reported in 1998. Other cases in this group are presumably caused by inorganic compounds such as various metals and well chemicals.

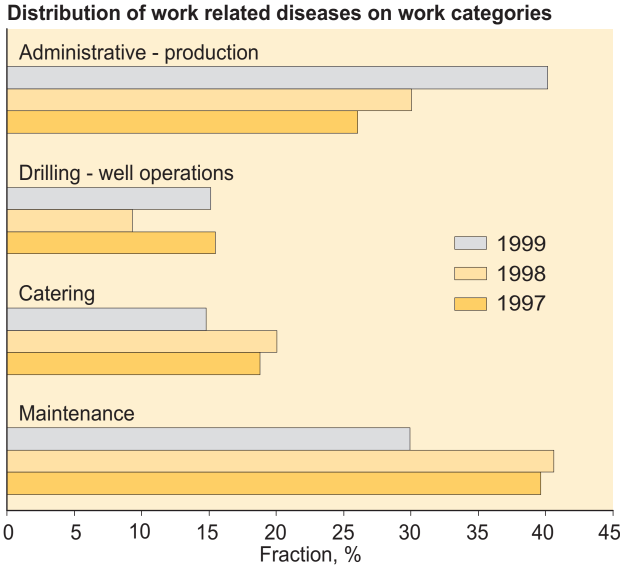
Noise-induced hearing loss has been discussed above. In addition, 13 cases of noise-induced tinnitus were reported (these have been included in the group "Other" diseases).

Undiagnosed conditions include various symptoms that are due to exposure to undesirable working environment factors, but which are difficult to classify as disease. These also include sleep disturbances. It seems obvious that many people experience sleep disturbances after having worked a so-called swing shift. This shift system was listed as the cause of 25 cases in this group, as compared with 71 cases in 1998.

The group "Other" includes diseases that do not fall under the categories mentioned above. This group includes inter alia diseases of the respiratory organs such as asthma and bronchitis, and cases of respiratory irritation caused by airborne irritants such as oil vapor and smoke from welding. Three cases of asbestos-related lung disease have also been reported. This relates to workers who have been exposed during previous employment, and who have now developed asbestos-specific changes in the pleura. Isocyanate exposure is listed as the cause of two cases of bronchial asthma, and one case of respiratory symptoms. The fact that a total of three cases of disease have been reported after exposure to isocyanates shows that continued preventive efforts are also required in this area. The fact that a relatively large incidence of disease attributed to isocyanate exposure was reported in both 1999 and 1998 (a total of nine cases), may be due to the attention these types of substances have received in recent years.

The various position categories that were exposed to work-related diseases are shown in Figure 2.7.3. Workers within the drilling sector have normally been perceived as being particularly vulnerable. However, taking into account that this function performed 27.2 per cent of the total man-hours, the per centage of cases is considerably lower than would be expected, even though the percentage has increased to more than 15 per cent in 1999 as compared with under ten per cent in 1998. The proportion of reports for the catering staff group declined somewhat compared with the previous year. The percentage in 1999 was 14.8, which is considerably higher than the comparable number

Figure 2.7.3
Distribution of work related diseases on work categories



Safety and working environment

of man-hours for this group (10.2 per cent). In 1999, the number of reported incidents in the construction and maintenance group was somewhat lower than the previous year. This group was responsible for 38.9 per cent of the total man-hours, but accounted for 29.9 per cent of the reported incidents of disease. The percentage of cases in administration and production rose, but this can be attributed to an increased volume of work in this group.

2.8 OIL AND GAS LEAKS, FIRES AND NEAR-FIRES

Oil and gas leaks

In this context, oil and gas leaks mean unintentional leaks that have the potential of being ignited. Other leaks and unintentional emissions/discharges of oils or chemicals that may be hazardous to the environment are discussed in Chapter 3, which deals with environmental measures in the petroleum activities.

Table 2.8.1 provides an overview of the reported oil and gas leaks over the past five years. Two of the leaks that occurred in 1999 are characterized as major, based on an overall assessment of the events. This assessment includes the amount of the emission/discharge, potential danger and causal relations. The two leaks that are characterized as major were both caused by inadquate planning. One of the two incidents revealed serious defects in the work permit system.

In addition to the 165 leaks registered in the table, in 1999 the Norwegian Petroleum Directorate also received reports of a number of oil and gas leaks that were considered to be insignificant. The total number of leaks reported in recent years has been stable, with a falling trend for medium/major leaks. When compared with the production volume on the Norwegian shelf, the number and seriousness of the gas leaks is relatively stable. Compared with the number of installations, the number of leaks per unit has fallen somewhat.

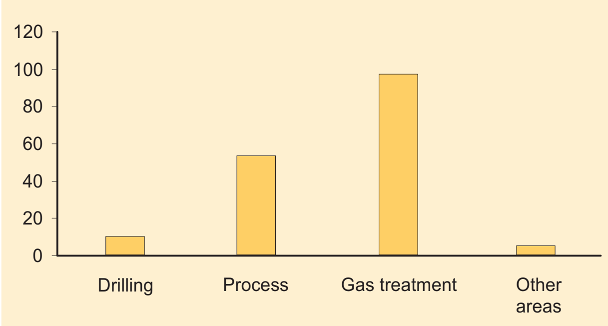
Table 2.8.1
Hydrocarbon leaks during the period 1995-99 distributed according to severity

Year	Minor	Medium	Major	Totalt
95	98	33		131
96	120	32	4	156
97	156	27	3	186
98	128	26	3	157
99	142	21	2	165

Table 2.8.2
Distribution of hydrocarbon leaks according to severity and method of detection

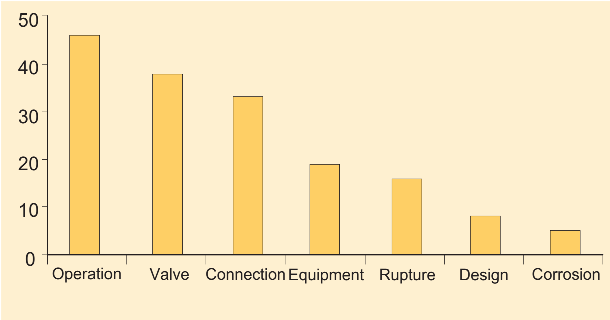
Severity	Number of leaks	Automatic detection	Manuel detection
Major	2	2	0
Medium	21	12	9
Minor	142	33	109
Total	165	47	118

Figure 2.8.1
Area where hydrocarbon leaks occurred



Drilling:	Areas for drilling and well activities
Process (oil):	Areas for systems containing oil (wells, separators, etc)
Gas treatment:	Areas for systems normally containing gas only (compression, gas treatment, flare, etc)

Figure 2.8.2
Main group of faults resulting in gas leaks



Operation:	Faulty operation, inadequate procedures or planning
Connection:	Deficiencies in flanges or connections
Equipment:	Deficiencies on equipment or instruments
Rupture:	Cracks or fractures

Table 2.8.2 shows that minor leaks, such as from valves and couplings, are not usually detected automatically. However, the reporting of such incidents is also of great value in the work to identify problem areas and causal relations. Both of the major leaks and about half of the medium-sized leaks were detected automatically. The Norwegian Petroleum Directorate has noted that the operating companies' reports have concluded that large gas leaks should have been detected by automatic detection systems. This indicates that there is still room for improvement as regards the detection systems.

The Norwegian Petroleum Directorate notes that the majority of the leaks occur in areas and equipment related to gas treatment or compression, and that there has been an increase in the number of such leaks as compared with previous years (Figure 2.8.1).

Figure 2.8.2 illustrates the same trend as in previous years, in that operational errors, valve leaks and leaks from couplings contribute to the majority of the incidents. Both of the major leaks were caused by operational error. In 1997 and 1998, several serious incidents were related to corrosion/breach, while only one medium-sized event was recorded in this category in 1999.

Fires and near-fires

In the last year, we have seen an increase in the number of reported fires and near-fires as compared with the four previous years (Table 2.8.3). Most of the cases are minor events (near-fires) in which smoke, flames or overheating has been registered for a short period of time. Four fires are classified as medium because the duration has been longer and there were larger volumes of smoke/flames (Table 2.8.4).

Two of the four fires classified as medium were the result of fires in electrical equipment. The fires led to extensive smoke development which spread to important safety areas and rooms (control room and living quarters). One fire also occurred in a fire pump. The fourth fire in this category occurred in an overpressure welding tent when a welding gas leak was ignited inside the tent. A welder suffered burns as a result of this fire.

Table 2.8.3
Fire and near-fires 1995-1999

Year	Minor	Medium	Major	Total
95	11	7		18
96	15	3	1	19
97	22	2	1	25
98	17	4	1	22
99	38	4		42

Table 2.8.4
Causes of fires in 1999 ditributed by size

Ignition source	Minor	Medium	Total
Welding	2		2
Torch cutting	3		3
Electrical	8	2	10
High temperature	22	1	23
Other	3	1	4
Total	38	4	42

Fires caused by high surface temperatures clearly account for the largest group of fire causes, but all but one were minor incidents. Ignition on hot surfaces has occurred in connection with

- turbines,
- bearings in rotating equipment,
- other areas in rotating equipment,
- heating elements.

The electrical fires were caused by factors such as:

- short circuits in cables, junction boxes or switchboard,
- defects in electrical equipment.

2.9 DAMAGE TO LOAD-BEARING STRUCTURES AND PIPELINES

The Norwegian Petroleum Directorate receives reports of damage to and incidents involving load-bearing structures and pipeline systems. The information is gathered in the CODAM database. In 1999, there were reports of 10 incidents related to load-bearing structures and 11 related to pipeline systems. The database now contains data concerning a total of 3,260 incidents related to load-bearing structures and 2,209 related to pipeline systems.

Subsea pipelines and risers

The majority of the damage to and incidents involving pipeline systems is classified in the categories “insignificant” and “minor”. These are incidents that do not require much repair or follow-up. Incidents in the “major” category include, for example, leaks in pipelines and risers, incidents involving buckling of pipelines, as well as external and internal corrosion, etc., depending on the scope of the damage and the criticality.

In 1999, there were five “major” incidents and damage involving pipelines and risers:

- Two of the incidents occurred during installation of a 20" oil pipeline when unforeseen circumstances led to the occurrence of two long free spans of 293 meters and 362 meters respectively. Free span means that the pipeline is not resting on the seabed or any other form of support. These free spans were corrected by rock dumping and construction of supports.
- After a leak from an 8" flexible gas lift pipeline was registered, a crack of 15x10 mm was ascertained to be the cause of the leak. Vertical buckling of the pipeline had occurred in the area around the crack. This caused the crosswise reinforcement to slide out of position, resulting in an opening and thus a rupture in the pipeline. The damage was repaired by cutting out a 360-meter length of the flexible pipeline and replacing it with an equivalent length of steel pipeline.
- Leakage was observed from a subsea connection on a 20" oil and gas pipeline. The leak probably occurred in connection with temporary shutdown. The leak stopped when the pipeline was pressurized.
- A crack was also discovered in an 8" flexible pipeline for water injection. The crack is located near the flotation buoy on the riser. So far, the cause of the crack has not been determined. The pipeline is also used for fire water supply, but at a lower pressure.

Load-bearing structures

In 1999, no “major” damage or incidents were reported concerning load-bearing structures. However, one incident which, by itself, was classified as “minor” has proven to have a more extensive scope upon closer examination, as the operating company has discovered the same type of damage in other cargo tanks on the installation in question.

The reported damage concerns a mobile production installation where in connection with inspection of the cargo tanks a 430x80 mm crack was found in a 12 mm thick plate. The crack was presumably initiated in the fabrication phase, and further affected by induced hydrogen in a heated zone, flaking of paint and several incidences of corrosion pitting. Welding defects with slag encasement of about 530 mm. The findings of the inspection will lead to the emptying and cleaning of all tanks on the production installation so that they can be inspected. Discovered damages have been rectified.

Collision between vessels and installations

Eleven collisions between vessels and installations were reported in 1999, compared with an average of two collisions per year during the period 1988-1999. Mobile drilling rigs were involved in six of the incidents, four collisions were with permanent installations, and one collision was between a vessel and a production ship.

The scope of the damage in the individual collisions varies from minor paint damage on both vessel and installation to major dents, holes in the side of craft, tearing down of equipment such as antennas, etc. In three of the incidents, mobile drilling rigs and permanent installations suffered damage in the collision with the vessel. Similarly, six vessels suffered damage.

2.10 DIVING

Diving activity

During 1999, 416 surface-oriented dives and 451 bell runs totaling about 57,000 man-hours in saturation were carried out on the Norwegian shelf and in connection with Norwegian pipelines in foreign sectors. This represents an increase in surface-oriented diving, but a reduction in saturation diving as compared with 1998.

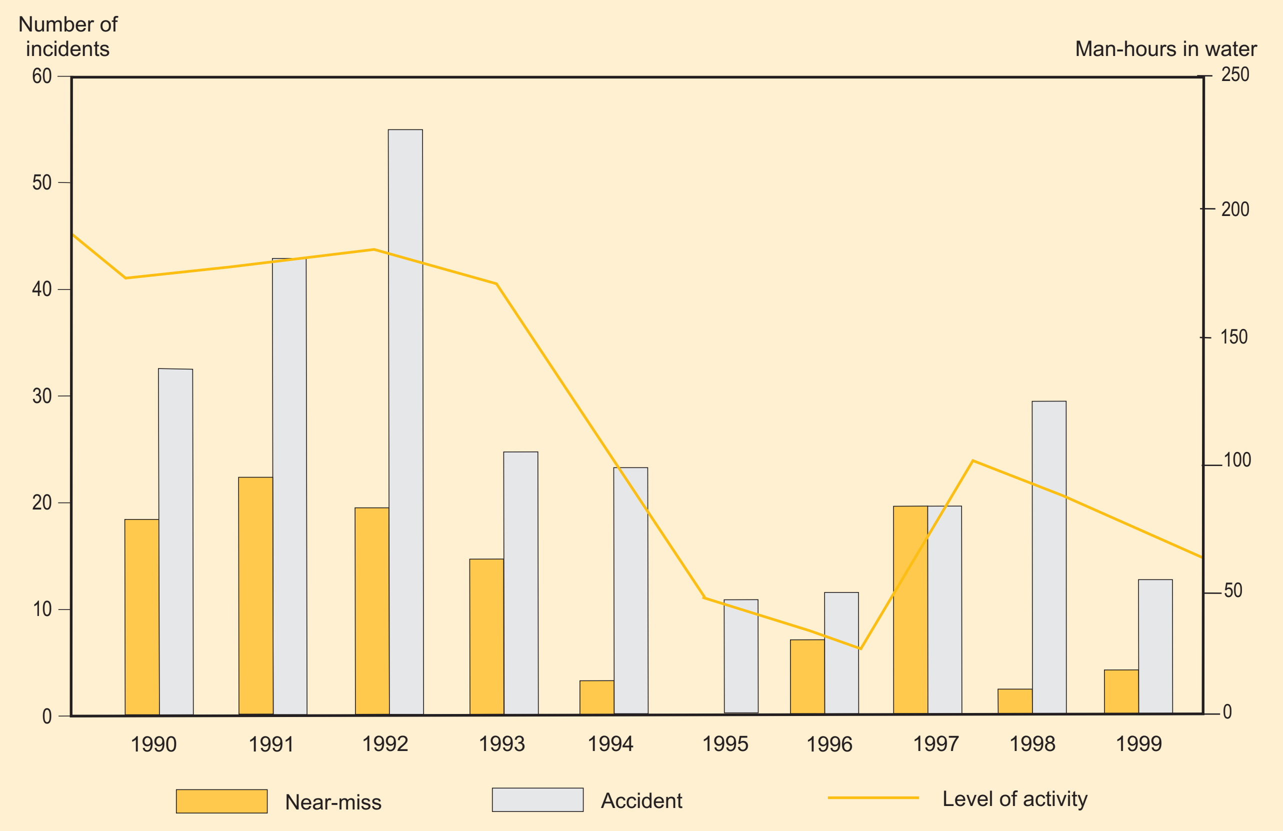
The diving activities have been divided among inspection, maintenance and construction activities on fields where Elf, Esso, Hydro, Phillips, Saga, and Statoil are the operators. Diving in connection with construction work has constituted a large portion of the activity.

Personal injuries in connection with diving

Figures 2.10.1 and 2.10.2 present a summary of the number of undesirable incidents connected with diving activities reported to the Norwegian Petroleum Directorate for the years 1985-1999. The incidents are subdivided into the categories near-miss, personal injuries and fatality. Personal injury is defined as an incident that requires medical treatment, first aid, or that entails absence extending into the next 12-hour shift. A near-miss is a dangerous situation, which under slightly altered circumstances, could have led to death or serious personal injury.

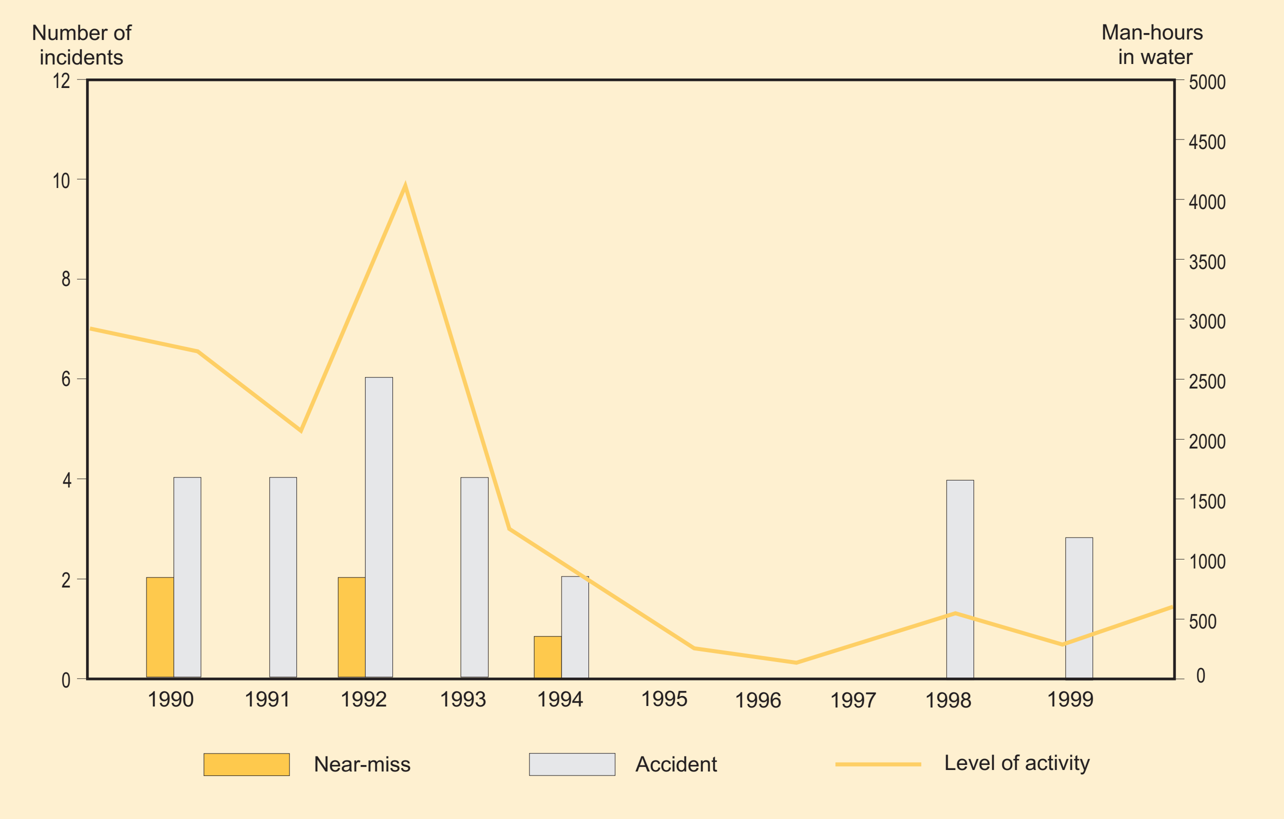
Figure 2.10.1 shows that the number of reported personal injuries associated with saturation diving in 1999 have been reduced compared with the previous year, more or less

Figure 2.10.1
Incidents in saturation diving



Safety and working environment

Figure 2.10.2
Incidents in surface oriented diving



in conformance with the reduced activity level. Of the 13 reported personal injuries in connection with saturation diving in 1999, only one was of a serious nature (loss of fingertip). Of the remaining 12 incidents, eight concern infections in the form of inflammation of the external auditory canal and skin infections.

Four near-misses were reported in connection with saturation diving, of which one is characterized as serious. This incident occurred during an underwater lifting operation when a protective sheath weighing one tonne came loose from the lifting device and fell near a diver.

There have been a number of serious near-misses linked to underwater lifting operations in recent years.

Throughout the entire period, the number of reported near-misses has been low compared with reported personal injuries. This indicates that there is probably a general underreporting of incidents.

One case of serious bends in connection with surface-oriented diving was reported in 1999. The last case of bends in connection with this type of diving was reported in 1991.

As regards saturation diving, there have been no reported cases of bends since 1993.

Experience gained from supervision of the diving activities

Through its supervision activities in 1999, the Norwegian Petroleum Directorate has noted unsatisfactory attention to diving safety aspects, particularly in the planning and preparation of the diving operation. Among other things, this applies to lack of knowledge concerning problem areas in diving operations.

Training

No saturation divers were trained in Norway in 1999. During the course of the year, the Norwegian Professional Divers' School and the National Divers' School have trained a total of 74 divers who have been issued Class 1 certificates.

Research and development in the area of diving

In 1999, the Norwegian Petroleum Directorate participated on the board of directors and in project management groups in research programs related to diving. This involvement helps ensure that the Directorate's professional and technical staff is kept up-to-date with regard to ongoing R&D activities in this field.

In November 1999, the annual diving seminar was held as a joint seminar for both open sea diving and diving in sheltered waters.

International cooperation on diving

The Norwegian Petroleum Directorate is the chairman of the European Diving Technology Committee (EDTC). In 1999, the committee's work included preparation of an international standard for training physicians who work with divers and hyperbaric medicine. This standard has been developed in cooperation with the European Committee for Hyperbaric Medicine (ECHM).

2.11 TOPICAL SUBJECTS IN 1999

Chemicals and chemical health hazards

In 1999, considerable attention was given to the use of chemicals and the health hazard this represents. The Norwegian Petroleum Directorate has participated in a project led by Statskonsult in which several public bodies participate. This work has examined how legislation in the field of chemicals can be simplified. On assignment from the Storting, the Office of the Auditor General commenced a project related to chemical regulations for chemicals. A comprehensive process is underway within the EU to revise and restructure directives relating to chemicals.

The employees' organizations are concerned with the use of chemicals, particularly products containing isocyanates. These products are primarily used in paint products in the petroleum activities. Most companies have stopped using paint products that contain isocyanates because of the health hazard. However, this does not mean that this health hazard has been removed, as large quantities of this type of paint coating exist on the installations. This pain coating will emit cyanide compounds when heated, e.g. in connection with torch cutting or welding. The Norwegian Petroleum Directorate participated in a project under the direction of NTNU that examined the occurrence of serious health ailments caused by products containing isocyanates among persons who carry out surface treatment. Preliminary results from this survey indicate that the occurrence of health injuries is low.

Through its supervision activities, the Norwegian Petroleum Directorate has noted that the companies often do not have the systematic approach required by the regulations when dealing with chemical health hazards. The work in this area is often characterized by happenstance, sporadic survey activities, measurements that are not representative, weak professional grounds for conclusions, etc.

Therefore, the Norwegian Petroleum Directorate has carried out coordinated supervision activities aimed at operating companies that have installations in operation on the Norwegian shelf. The purpose has been to assess the companies' ability to carry out comprehensive risk assessments of the chemical working environment, but also to contribute to the acquisition of new knowledge regarding risk factors related to work operations, equipment and processes that are typical in today's operations. The supervision was also aimed at facilitating the exchange of experience between the companies in this area.

The supervision revealed considerable variation among the companies as regards the ability to carry out risk assessments of the chemical working environment. Some of the companies had such great shortcomings as regards competence, methodology, collection and use of data that they were unable to carry out risk assessments. On the other hand, there were companies who carried out good assessments and could present new knowledge with significant exchange value.

In addition to the follow-up of each individual company, the Norwegian Petroleum Directorate will also collect information regarding the methodology for chemical risk assessment in the working environment, and clarify the Directorate's requirements and expectations. In 2000, provision will be made for activities to spread information to the industry regarding chemical health hazards.

Risks associated with helicopter transportation

The Norwegian Petroleum Directorate has participated in, and continues to participate in several forums that evaluate factors related to helicopter safety on the Norwegian shelf. Among other things, the Norwegian Petroleum Directorate participated as an observer in work carried out by SINTEF and OLF. The Norwegian Petroleum Directorate is also an active contributor in the "Council for Helicopter Safety on the Norwegian Continental Shelf".

Transportation of personnel by helicopter is one of the greatest risk elements for personnel working on the Norwegian shelf. Therefore, proper safety when using helicopter transportation depends on continuous follow-up of the safety management in the operating companies and on the part of the helicopter contractors. Audits carried out by some operating companies aimed at helicopter contractors have shown that it is also necessary for the supervisory authorities to focus on safety management in connection with transportation of personnel via helicopter.

In cooperation with the Civil Aviation Inspectorate (LFT), the Norwegian Petroleum Directorate conducted several coordinated supervision activities in 1998 and 1999 aimed at the use of helicopters in the petroleum activities. The supervision activities have covered both operating companies and helicopter contractors. In addition, the LFT carried out its own supervision activities aimed at the helicopter contractors' safety and quality systems.

All of the parties involved in the supervision activities have been consistently positive to such coordinated supervision. Among other things, this form of supervision has contributed to clarifying the interfaces between petroleum and aviation regulations, both between the supervisory authorities and vis-a-vis those who use the regulations.

Lifting gear and lifting operations

A total of 52 undesirable incidents related to lifting operations were reported to the Norwegian Petroleum Directorate in 1999, compared with 44 in 1998. This figure includes all lifting operations, including lifting operations in connection with drilling. The number of incidents involving personal injury has gone up from 12 in 1998 to 15 in 1999. One of these incidents led to a person losing his life during manual intervention in connection with remote-controlled pipe handling in the derrick. The circumstances surrounding this tragic accident are described in more detail in a safety notice issued by the Norwegian Petroleum Directorate. The incident is being investigated by the police.

The most important observations of areas with obvious potential for improvement, as revealed in the Norwegian Petroleum Directorate's supervision activities directed towards lifting gear and lifting operations in 1999, are as follows:

- Operational procedures, and lack of discipline concerning compliance with such procedures.
- Knowledge regarding safety and safety attitudes in connection with lifting operations.
- Use of experience from accidents and undesirable incidents.
- Involvement of technical and operational expertise in operations and follow-up of lifting gear.
- Selection of lifting gear on production ships and consideration for the relevant operational circumstances.
- Planning and providing for the use of lifting devices on mobile production installations.

In 1999, the Norwegian Petroleum Directorate started the project “Causal relations in connection with lifting operations”. The purpose of the project is to map and analyze all reports of undesirable incidents associated with the use of offshore cranes from all of the operators on the Norwegian shelf. The goal is that the results of the work shall result in proposed measures that can reduce the number of accidents and undesirable incidents when carrying out lifting operations. Conclusion of the project is planned for March 2000, with presentation of the results.

On the basis of the number of serious incidents associated with the use of the personnel winch, this will be an area that will be followed up during the year 2000.

«Green water» - risk of wave damage to mobile production installations

There are currently five mobile production installations in use on the Norwegian shelf. Two of these were installed in the summer of 1999, and therefore have limited experience with difficult weather conditions. Three of these installations have been in their respective areas for at least one winter season, and have experienced that waves wash over the deck area (“green water”), or that sea spray has caused damage to equipment.

Green water can represent a safety risk because:

- personnel on deck may be injured by the waves that wash over the deck,
- the living quarters may suffer damage, with associated danger to personnel who are in the quarters,
- safety-critical equipment may be damaged,
- the production equipment may be damaged, with associated risk of interruption of production.

Traditional installations such as steel jackets, gravity base structures and semi-submersible installations are designed so that there is clearance between the highest wave crests and the underside of the deck. Tankers, however, have been designed to tolerate green water. When the first production installations formed like ships’ hulls were designed, the risk of waves on deck was overlooked or underestimated with regard to the strain on deck equipment. The cause of this seems to be that these installations were designed with a point of departure in maritime traditions, and there has been little exchange of information between the builders of hulls and deck equipment. In model tests carried out early on, green water was not viewed as a significant problem, in part because the model tests did not include the circumstances that are most critical with regard to green water. For example, the sea conditions that create the greatest loads on the anchor systems do not necessarily cause waves on deck.

The Norwegian Petroleum Directorate believes that the experience from green water in connection with operation of tank ships can be transferred and utilized when designing floating production installations.

New analyses and model tests have recently been performed for most of the mobile production installations, and these analyses show that green water is a potential problem for all of the installations. Various types of measures have been implemented in order to avoid damage due to green water. These measures can be divided into two main groups:

- Measures that create physical protection, such as enhanced bulwarks, breakwater walls or local reinforcement of equipment and structure,
- Operational limitations, such as reduced draught, ”trimming” of the hull so that the fore is higher than normal, and restrictions with regard to the presence of personnel in areas where green water can occur.

The Norwegian Petroleum Directorate has taken the initiative for a series of meetings with operators that have mobile production installations in use, and have carefully followed the work the companies have done in this area.

New knowledge regarding fire and explosion

Previous annual reports have included accounts of a major research project, largely carried out in the U.K. in the field of fire and explosion. The project was supported by the Norwegian operating companies Norsk Hydro and Statoil, and has inter alia contributed extremely significant and useful knowledge regarding the course of explosions and model simulation of such explosions.

In order to prepare guidelines and procedures to ensure proper use of the simulation tools in connection with the design of petroleum installations, a group has been set up under the direction of the organization of operating companies on the British shelf (UKOOA). Statoil and Norsk Hydro participate in this group, together with British authorities and the Norwegian Petroleum Directorate. In parallel with this work, the Norwegian operating companies, in close collaboration with the Norwegian Petroleum Directorate, have prepared a separate procedure for use when designing new petroleum installations. The procedure has been published in the petroleum community in Norway, thus ensuring that today’s knowledge within this field is incorporated in connection with new developments.

Authorities’ cooperation on injury statistics

In 1999, the Norwegian Petroleum Directorate continued its cooperation with the British Health & Safety Executive (HSE) regarding harmonization of accident statistics and reporting of work-related diseases. There are still significant differences in reporting requirements and routines on the

British and Norwegian shelves, which makes it difficult to compare injury data from the two countries.

One important difference is the criteria for reporting personal injuries. On the British shelf, injuries are reported when they lead to absence for more than three days, while on the Norwegian shelf, injuries are reported when they entail absence that extends into the next shift, or require medical treatment.

The definition of serious personal injuries is, however, the same. A comparison of serious personal injuries in relation to the number of workers involved in petroleum activities on the two countries' shelves indicates that the frequency of serious personal injuries is at about the same level.

Both of the countries' authorities are in the process of implementing new systems for registration of industrial accidents. In this context, an attempt will be made to achieve common classifications that will make it easier to compare data from the British and Norwegian petroleum activities.

3.1 CONSIDERATION FOR THE ENVIRONMENT

Consideration for the external environmental has attained a central position in the formulation of petroleum and energy policy. The Norwegian Petroleum Directorate's paramount objectives and goals reflect the Directorate's responsibility and tasks regarding the environment. The consideration for the external environment is addressed as an integral part of the work to ensure sound management of the Norwegian petroleum resources.

The main activities in this work are stipulation of regulations and other frameworks for the activities, preparation of reports and professional advice to the responsible ministries, and supervision of the activities carried out by the operating companies. Other activities are related to participation in national and international forums that work on external environmental issues.

3.2 MILJØSOK

MILJØSOK was established in 1995 in order to stimulate a more binding cooperation between the authorities and the oil and gas industry in order to solve the most important environmental challenges. The MILJØSOK report was submitted to the Ministry of Petroleum and Energy in 1996. The report provides a comprehensive environmental status and description of the environmental challenges for Norwegian petroleum activities, a review of technical/economic alternatives and an evaluation of the instruments used in climate and environmental policy.

The next phase of MILJØSOK started in 1997 when a secretariat was established in connection with OLF (Norwegian Oil Industry Association), as well as a separate Council and Cooperation Forum. The Norwegian Petroleum Directorate participates in both the MILJØSOK Council and the Cooperation Forum, and the Directorate has participated in several working groups established by MILJØSOK in 1999.

3.3 AUTHORITIES AND FRAMEWORKS

The Norwegian Petroleum Directorate and the Norwegian Pollution Control Authority have the authority to supervise the petroleum activities under the Petroleum Act and the Pollution Act. The Norwegian Petroleum Directorate also enforces the Act concerning CO_2 tax on the shelf.

The Petroleum Act requires that all activities be carried out in a responsible manner which safeguards the safety of personnel, the environment and financial values.

The Pollution Act has the objective of ensuring proper environmental quality so that pollution and waste do not lead to health hazards, do not affect general well-being or harm nature's capabilities of production and self-renewal.

The regulations regarding management systems, risk analyses and emergency preparedness have authority in both of the central acts mentioned above, and are administered by the Norwegian Petroleum Directorate together with the rest of the technology regulations and the Working Environment Act.

3.4 SUPERVISION OF THE ACTIVITIES

Security against pollution is also covered under the safety concept as it is applied in the shelf activities, and supervision of environmental measures and environmental activities is an integral part of the Norwegian Petroleum Directorate's supervision activities. In 1999, the Norwegian Petroleum Directorate, in cooperation with the Norwegian Pollution Control Authority, carried out two rounds of supervision that were specifically directed towards the operators' safeguarding of the external environment. The Norwegian Petroleum Directorate also carries out supervision of internal management systems for operators and contractors in order to ensure that the activities are planned and implemented in accordance with the authorities' requirements and goals and acceptance criteria in the companies.

The comprehensive integrity of the authorities' supervision work is ensured through the Norwegian Petroleum Directorate's coordinating role in relation to the Norwegian Pollution Control Authority.

In its supervision of exploration drilling in environmentally sensitive areas, the Norwegian Petroleum Directorate has placed particular emphasis on preventive measures which the operators implement. In addition, the Directorate has followed the operators' work on stipulating acceptance criteria for environmental risk, in other words, the risk the operator itself can accept for its activity.

The Norwegian Petroleum Directorate also carries out supervision of the use of equipment that measures fuel consumption and the quantity of gas used for flaring and cold venting. Collection of the CO_2 tax on the shelf is the

Figure 3.4.1
Emissions of CO_2 per Sm^3 oe. Emissions from use of diesel are not included.

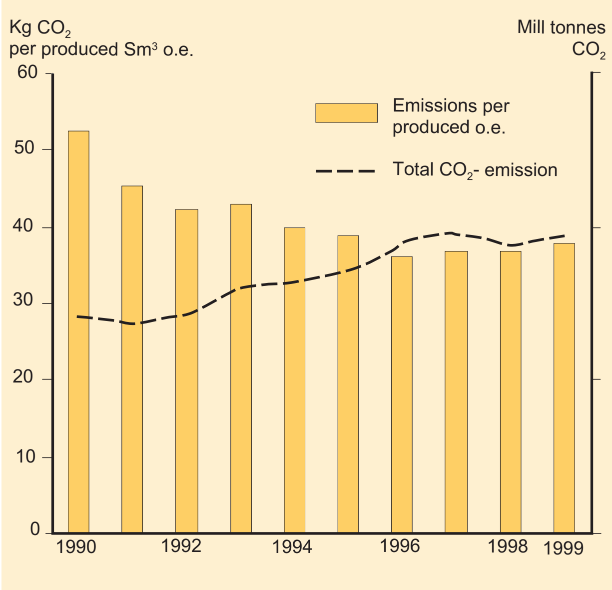
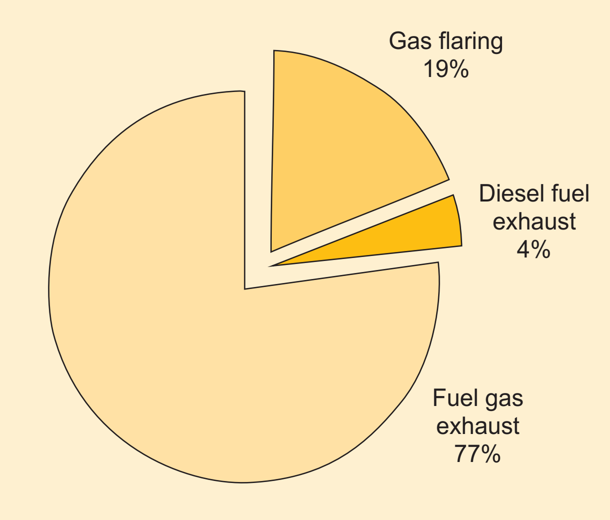


Figure 3.4.2
CO_2 - emission sources, 1999



responsibility of the Norwegian Petroleum Directorate, and the Directorate makes an annual evaluation of the companies in order assess the impact of the tax on CO_2 emissions.

Preliminary figures show that CO_2 emissions from taxable activities on the shelf were 8.5 million tonnes in 1999. This constitutes about 88 per cent of the total emissions of CO_2 from the petroleum activities as shown in Figure 3.4.1. Figure 3.4.2 shows how the emissions are divided by source.

The Norwegian Petroleum Directorate receives immediate notification concerning accidental oil spills larger than 1 m^3 to sea. In September of 1999, the Directorate started using a new registration system that provides for considerably better accessibility and overview of incidents including accidental oil spills. After this system was put into use, eight oil spills have been registered. However, none of these were of a size that entailed special recovery measures, etc. The Norwegian Petroleum Directorate also carries out supervision of the companies' systems for registering smaller spills than are covered by the reporting criterion with the aim of improving equipment and work procedures.

3.5 THE EXTERNAL ENVIRONMENT

When the Norwegian Petroleum Directorate evaluates impact analyses, plans for development and operation and applications for consent, the environmental aspects are a natural part of and fully integrated with the rest of the Directorate's evaluation. Great emphasis is placed on the ability to make use of technology which reduces the volume of emissions and discharges, and the Directorate believes it is important to work to influence the industry to develop efficient and environmentally friendly solutions that also provide the best possible economy.

The Norwegian Petroleum Directorate prepares annual forecasts for emissions of CO_2, nitrogen oxides (NO_x) and volatile organic compounds (nmVOC and methane). The forecasts are an important basis from which to evaluate policy instruments so that national and international commitments may be followed up.

Routines and systems for annual reporting of historical emissions and discharge from the fields on the shelf have been prepared in cooperation with SFT.

In 1999, the Directorate has participated in the authorities' negotiation delegation working on a voluntary agreement with the industry regarding reduction of nmVOC emissions associated with buoy loading. However, no agreement has been reached on this issue.

Together with the Ministry of Petroleum and Energy, the Norwegian Petroleum Directorate has prepared an annual environmental publication that provides an overview of environmental aspects on the Norwegian shelf. The Directorate has also contributed to the Ministry of Petroleum and Energy's work on preparing an environmental action plan for the various sectors of the petroleum and energy industry.

3.6 DISPOSAL OF INSTALLATIONS

According to the Petroleum Act, the licensees shall submit a decommissioning plan 2-5 years before the expected termination of the use of an installation or the expiration of the licence. The plan shall contain a proposal for continued production or shutdown of production and disposition of the installations.

Norwegian authorities have appointed an inter-ministry committee whose task is to develop a national policy for disposition of installations that have been used in the petroleum activities. This committee has also contributed to the international work under the Oslo and Paris Convention (OSPAR).

In the summer of 1998, OSPAR adopted a resolution regarding disposal of installations in the Convention area. The resolution means that the following installations must be brought to land:

- Subsea installations
- Floating steel installations
- Small, permanent steel installations (substructure weight < 10,000 tonnes)
- Upper part of large, permanent steel installations (deck facilities and substructure down to the uppermost part of the piles on installations with a substructure weight > 10,000 tonnes)
- Deck facilities on concrete installations

Exceptions may only be granted if the installations can serve other uses or if an overall evaluation in the individual case shows that there are preponderant reasons for disposal at sea. An exception from the prohibition on sea disposal is made for the lowermost part of large, permanent steel installations (substructure weight > 10,000 tonnes) placed on site prior to 9 February 1999, and the substructure on concrete installations. These parts of the installations may be evaluated on a case by case basis. A proposal regarding sea disposal will be presented to OSPAR.

The Norwegian Petroleum Directorate is assisting the Ministry of Petroleum and Energy in formulation of guidelines for a decommissioning plan. A study program to evaluate disposal of pipelines has been carried out under the direction of the inter-ministry committee. The clarification program was completed in 1999 and a summary report has been prepared. The issue is scheduled to be presented to the Storting in the spring of 2000. The Norwegian Petroleum Directorate also contributes with assessments related to the decommissioning plans for the individual fields.

3.7 GREENING OF GOVERNMENT - GREENING OF NPD

The Norwegian Petroleum Directorate is one of ten governmental bodies which, over the course of two years, is testing measures and systems in order to make operations as environmentally friendly as possible. Emphasis is placed on implementing the project so that the work can subsequently be continued in all governmental operations. The Norwegian Pollution Control Authority is assigned the responsibility for leading the project, while the Ministry of the Environment and the Ministry of Labor and Government Administration together are responsible for the project, which started in September 1998.

The project has six commitment areas: energy consumption, purchasing, construction, transportation, waste management, use of information and communication technology (ICT).

In this project, the Norwegian Petroleum Directorate focuses on how we can reduce our own environmental burdens with the aid of ICT. The action plan and quarterly progress reports are available on our home page http://www.npd.no.

One of the Norwegian Petroleum Directorate's main goals is to support internationalization and development aid through active use of the Directorate's expertise and contacts. Efforts related to this fall within the following categories:

- cooperation with developing countries within the framework of the cooperation agreement with NORAD,
- cooperation with the PETRAD foundation,
- cooperation with Russian regulatory bodies with the support of the Ministry of Foreign Affairs,
- bilateral cooperation with petroleum authorities and through various international forums.

4.1 COOPERATION WITH NORAD

In 1999, the Norwegian Petroleum Directorate's development aid financed by NORAD amounted to approximately five man-years. The majority of the assistance has been directed towards the following cooperating countries: Angola, Namibia, South Africa, Mozambique, Eritrea, India, Bangladesh, Vietnam and Nicaragua. The Norwegian Petroleum Directorate also continued its cooperation with the Coordinating Committee for Coastal and Offshore Geoscience Programmes in East and Southeast Asia (CCOP) and Southern Africa Development Community (SADC).

The Norwegian Petroleum Directorate has come a long way towards meeting NORAD's objective of establishing long-term cooperation agreements with relevant institutions in the countries concerned. All main projects are governed by such agreements. During the year, work has proceeded for new agreements with Angola and Bangladesh and these projects are scheduled for implementation next year. The form of institutional cooperation varies in the different countries. For some of the larger projects, attempts are made to contribute actively to the development of the cooperating institution by offering experience from the entire range of the Norwegian Petroleum Directorate's sphere of activities, both professionally and administratively.

Nicaragua (Instituto Nicaraguence de Energia INE)

The activity in 1999 has mainly been targeted on preparations for the first licensing round scheduled for 2000 and include a promotion workshop together with PETRAD and assistance in the use of map generating software and emergency preparedness planning. Based on a professional viewpoint, the NPD is of the opinion that the need for assistance to INE is very important at this stage in order for INE to be able to announce and award blocks in an expedient manner for the country.

An assessment of continued assistance to Nicaragua will be based on an evaluation of the program that has been carried out.

Angola (Ministry of Petroleum MINPET)

The Norwegian Petroleum Directorate has been involved in NORAD's projects related to Angola for several years and several Angolans have received training in the Norwegian Petroleum Directorate. Angola has also received support in connection with its work on statutes and regulations. Plans for further cooperation have been completed and presented to NORAD. In this connection, Angola was visited in the summer of 1999. A decision concerning institutional cooperation was made by NORAD at the end of 1999. The Norwegian Petroleum Directorate is evaluating stationing an advisor in Angola.

Namibia (Ministry of Mines and Energy – MME)

In previous years, the Norwegian Petroleum Directorate has assisted in the formulation of regulations and follow-up of drilling operations. Namibia has built up a small, but highly qualified petroleum management system; MME.

Namibia wishes to separate administration tasks from the state oil company, NAMCOR, so that the company can concentrate on commercial tasks.

Three workshops were carried out in Windhoek in 1999. In order to follow up the cooperation agreement, the NPD stationed an advisor in Windhoek on 1 December 1999. Several activities are planned for 2000, including assistance in developing new gas legislation, further development of supervisory methods, planning of promotion of the Namibian shelf, follow-up of plans for gas development, etc.

South Africa (Department of Mineral Resources and Energy – DME)

Organization of upstream oil and gas activities, establishment of framework conditions for marketing of natural gas in South Africa, organization of sales of petroleum, organization of state ownership interests in the petroleum sector and training are important areas for Norwegian assistance to DME. The project was in full swing in the spring of 1999 with EDRC at the University of Cape Town as the executing institution on behalf of DME. The Norwegian Petroleum Directorate assists EDRC in the work and it includes the use of Norwegian researchers and consultants. The project is carried out according to plan. ECON has been granted several study contracts within the "Downstream Gas" and "Liquid Fuel" projects. ECON has established an office in Cape Town in order to handle these contracts. The Norwegian Petroleum Directorate has assumed the responsibility of performing the initial »Upstream Oil and Gas» sub-tasks. An evaluation of the project work is being planned and will most likely be carried out in the spring of 2000.

Mozambique (National Directorate for Coal and Hydrocarbons – NDCH)

The Norwegian Petroleum Directorate has continued its support in the formulation of legislation, resource, pipeline and safety regulations and model contracts for the petroleum activities.

The Norwegian Petroleum Directorate has also assisted the NDCH with the follow-up of the plans for development of the Pande and Temane gas fields. If the projects are realized, they will be among the largest industrial projects in Africa. In addition, planning and construction of central data storage for seismic data and general institutional support have been important activities.

Recently, an evaluation of the project was carried out that will prove to be very useful in connection with a possible continuation of the program. A proposal for continuation will probably be presented in the spring of 2000.

NDCH as an organization has been strengthened considerably due to the fact that several of the new employees have undergone extensive training. Assistance has also been provided in order to develop planning and management systems for the organization.

Eritrea

The Norwegian Petroleum Directorate has provided assistance concerning establishment of framework conditions, resource planning, assessment of environmental impact, studies of future gas strategy, promotion of exploration areas, data storage and seismic surveying. The Ministry of Energy and Mineral Resources is the main cooperation partner.

The project will end this year, but there are still some funds left that may be used for next year. It will probably not be possible to extend the project with new funds until a permanent cease-fire is in place. After Anadarco has pulled out due to three dry wells, it will be a challenge for Eritrea to attract new capital for continued exploration of the petroleum potential.

The gas strategy study was completed, but progress was delayed due to the political instability in Eritrea.

It appears preferable that some seismic data is reprocessed in order to improve the data packages that are used when marketing the exploration areas. This work, and possibly a workshop, appears to be relevant activities for 2000 based on the remaining funds.

Bangladesh

The Norwegian Petroleum Directorate has cooperated with Bangladesh for several years. In recent years, the cooperation has been dependent upon internal problems within the country and the question of how Bangladesh will organize its petroleum management system. It has been decided that a Hydrocarbon Unit will be established under the Ministry of Energy and Mineral Resources.

In this connection, a project was established in the summer of 1999. After a representative from the Norwegian Petroleum Directorate visited Dhaka in the autumn, the Norwegian Petroleum Directorate and HCU will prepare a work plan together for further activities under the project. A project organization for project implementation is being established in the Norwegian Petroleum Directorate.

India (Directorate General of Hydrocarbons – DGH)

The Norwegian Petroleum Directorate has assisted our cooperation partner, DGH, with transfer of experience concerning a large part of the Directorate's sphere of responsibility. Storage of large quantities of data, general data management, resource evaluation, development planning and implementation of safety audits are areas of focus for the assistance.

The project is in the final phase. DGH has proposed that funds intended for use by the DGH be used to increase the assistance from the NPD. A revised activity plan/budget has been submitted for approval to the Monitoring Unit.

A workshop on safety systems and continuation of cooperation relating to methods for resource evaluation is planned for 2000 and it may also be relevant to plan a visit by a DGH delegation to the Directorate. Preparations for direct dialog between DGH and Monitoring Unit in Bangladesh are also being evaluated.

Vietnam

The Norwegian Petroleum Directorate has continued its assistance concerning development of safety regulations and training in the area of safety management. The main cooperation partner is Petrovietnam (state oil company). SFT is cooperating in the same project.

The project is in the final phase and a draft final report is available. Some activities financed by the remaining funds from the project will be carried out until the spring of 2000.

A total of 10 workshop, 17 courses, one set of regulations, three guidelines and two system audits are part of what has been produced as part of the project.

Petrovietnam has presented ideas for new projects as a continuation of the cooperation with the Norwegian Petroleum Directorate. Implementation of safety regulations in relation to two large industrial projects (a new refinery and facilities for production, transportation and use of natural gas) have been proposed as the main commitment for a new project, as well as establishing a system for internal quality assurance/safety audits in Petrovietnam.

A program running over 3 – 5 years with an annual scope of NOK 3 million will have a considerable effect in relation to implementation of the new safety regulations. Representatives from the Norwegian Petroleum Directorate will assist Petrovietnam in completing the project application in January 2000.

CCOP

The Norwegian Petroleum Directorate has provided assistance to the cooperation organization in Eastern and Southeastern Asia that works on the mapping of petroleum resources in the area and lays plans for exploitation of these resources. A geo-professional advisor from the Norwegian Petroleum Directorate has worked at CCOP's secretariat in Bangkok. Over the years, a number of professional seminars have been organized in the area for members of the organization, inter alia with the assistance of PETRAD. Assistance has also been provided in the form of software and training in the use of modern analysis methods.

The plans for continuation of the Resource Evaluation and Planning Project (REP) were also presented at the annual meeting that was held in Hanoi in the autumn of

1999. The Norwegian Petroleum Directorate plans to have an advisor in place by the end of the first half of 2000 if the project plans are approved by NORAD.

PROJECT PLANS

SADC

The Norwegian Petroleum Directorate is preparing a work description to support the SADC in its work on transforming SADC TAU (Energy Sector: Technical and Administrative Unit, Luanda) into an energy commission. The Norwegian Petroleum Directorate assumes that this activity will start at the turn of the year.

Work is also underway on plans for a regional IT project for geotechnical services under SADC. The plan calls for the project to be managed and operated by the Petroleum Agency in South Africa. Several countries have already indicated that they are interested in using these services – without the services being actively marketed. (Mozambique, Tanzania, the Seychelles, Namibia).

If this model for implementation of regional SADC projects succeeds, it will be appropriate to take a look at earlier plans for projects such as harmonization of regulations, mapping of basins that extend over borders, regional competency enhancement measures, etc. By giving organizations in the region, with administrative capacity and technical expertise, responsibility and letting them handle the implementation, the chance of success will be greater and SADC may indirectly benefit from being the organization that organizes and finances the projects. This method of organizing may be combined with the new status of the SADC energy commission.

Nepal

Nepal is preparing an application for institutional support from the Hydrocarbon Promotion Project. The Norwegian Petroleum Directorate is following up the application process.

Togo

We are waiting on clarification from NORAD regarding implementation of the planned project concerning assistance for revising the petroleum act and support for a “Policy Seminar». NORAD will address this project when the Norwegian Ministry of Foreign Affairs finds that the political situation in Togo is acceptable for offering Norwegian support.

The Philippines

As a NORAD assignment, the Norwegian Petroleum Directorate assists the Philippine Department of Energy (DOE) in selecting consultants for assisting the DOE in the “Philippine Petroleum Resource Assessment” project. Early 2000 is being considered as the start-up time for the project.

Sao Tome

Two rounds of negotiation support have been carried out for Sao Tome. The negotiations with Mobil have been continued, but many important issues still remain before an agreement can be reached. An amendment to the existing agreement with Petroteam is being prepared after revised work specifications were received from Sao Tome. Additional efforts relating to this project should be evaluated based on the results of the next two negotiation rounds, i.e. February/March 2000.

4.2 COOPERATION WITH PETRAD

As a result of a pilot project carried out by the Norwegian Petroleum Directorate for NORAD during the period 1989-1993, Petrad was established as an independent foundation by the Norwegian Petroleum Directorate and NORAD on 1 January 1994.

The objective of the foundation is to place Norwegian expertise and competence in the fields of management and administration of petroleum resources at the disposal of managers from the authorities and national oil companies in Africa, Asia, Latin America, Oceania and Russia/CIS (Commonwealth of Independent States). This is accomplished by adapting seminars to inquiry and need by the authorities in the above-mentioned regions, in addition to the organizing of two eight-week courses each year, “Petroleum Policy and Management” and “Management of Petroleum Operations”, in Stavanger. All Petrad activities are aimed at senior and middle management personnel.

The activities are conducted through Petrad, which engages people who have a high level of competence in the petroleum activities. Up to now, Petrad has made use of more than 300 experts from around fifty companies, institutions and authorities as lecturers and resource persons in its courses and seminars. The eight-week courses in Stavanger integrate overall Norwegian experience and expertise within petroleum administration and management. Petrad also provides its course participants with comprehensive insight into the Norwegian petroleum industry and Norwegian culture through excursions and social events.

With the Norwegian Petroleum Directorate and NORAD as founders, Petrad is viewed as a neutral representative and conveyer of knowledge from the Norwegian public authorities. The response shows that Petrad has had a significant effect as a “door opener” and a creator of contacts in many countries.

The location of Petrad in the Norwegian Petroleum Directorate means that the Directorate has a close and profitable cooperation with the foundation. The Norwegian Petroleum Directorate participates with lecturers and resource personnel both at courses and seminars in Norway and abroad.

In 1999, the Norwegian Petroleum Directorate contributed to the implementation of Petrad’s two annual 8-week courses, “Management of Petroleum Development and Operations" and "Petroleum Policy and Management", held in the Norwegian Petroleum Directorate's offices, this time with 46 participants from 31 nations.

The Norwegian Petroleum Directorate has also contributed to the implementation of the following seminars in 1999:

- «Promoting Petroleum Investment», Managua, Nicaragua
- «Development Technology for Offshore Oil and Gas Fields», Xian, China
- «IOR/EOR Projects», Genting Highlands, Malaysia
- «Petroleum Economics and Finance», Maputo, Mozambique
- «Management and Operations of Gas Pipeline Systems», Vung Tau, Vietnam

This activity contributes to professional exposure to and understanding of different cultures while, at the same time, it increases the total expertise for those employees of the Directorate who are involved.

4.3 COOPERATION WITHIN RESOURCE MANAGEMENT

Annual meetings with Danish and British authorities

As an oil and gas province, the North Sea is basically divided between the UK, the Netherlands, Germany, Norway and Denmark. Even though the individual fields are quite different, there are many similarities among the fields in the North Sea area. The petroleum resource management problems encountered by government agencies in these countries are therefore similar in many ways.

Consequently, for many years the Norwegian Petroleum Directorate has carried out regular meetings with British and Danish resource management authorities who share basically the same responsibilities for their sectors as the Norwegian Petroleum Directorate does for the Norwegian shelf. For the UK shelf, it is the technical section of the Oil and Gas Division in DTI (Department of Trade and Industry) which is responsible for the resource aspect of exploration, development and operation activities. For the Danish shelf, the Danish Energy Agency (Energistyrelsen) has a similar responsibility.

The objective of the meetings is primarily to exchange opinions and experience from the respective activities. The UK activities are more mature by a few years compared with our activities. It has therefore been very useful to draw on their experience with regard to improved oil recovery, development of small fields and unitization. The Danes have particular problems related to chalk fields. It has therefore been valuable to acquire first-hand information on their experiences. Data management and the environment are other areas where it has been very useful to exchange experience. Close cooperation is envisaged also in these areas.

There were no meetings with the Danish authorities in 1999. The meeting with the British authorities was held in London on 2-3 December. The topic for the meeting was mutual review of experiences and status.

Annual meetings with other countries' authorities - exploration phase

Since 1983, annual meetings on technical issues have taken place between the Norwegian Petroleum Directorate and state administration units in other Northern and Western European countries with responsibility for exploration for oil and gas; England, Ireland, Denmark, Germany, the Netherlands, France, the Faeroe Islands and Norway take part in these meetings.

The responsibility for hosting the meetings is on a rotation basis among the various countries. Norway has hosted these meetings twice previously. France hosted the event in 1999.

The main issues of discussion at the meetings are geotechnical, exploration technology and data management issues, as well as challenges faced by the various countries in their efforts towards efficient discovery of new oil and gas resources.

The combined expertise and experience at these meetings are substantial, and the access to information is important for each individual participating country with a view towards developing optimal exploration strategies.

Annual meetings with other countries' authorities - fiscal metering

In those countries where Norwegian petroleum is landed, the authorities' responsibility and roles are stipulated in treaties and cooperation agreements. There is extensive cooperation on the part of the authorities in order to safeguard the individual country's requirements for fiscal metering. An important forum in this cooperation is annual meetings in which status and future activities in the area of metering technology are reviewed. The Norwegian Petroleum Directorate has established cooperation agreements with German, Belgian, British and French authorities.

The work on separate agreements for each individual transportation system into the UK was continued in 1999 and is expected to be completed in 2000. Norway ratified the change in the Frigg Agreement and the framework agreement relating to tie-back pipelines in a Storting resolution on 9 June 1999.

In 1999, the Norwegian Petroleum Directorate has followed up previous initiatives vis-à-vis the British authorities regarding identifying the need for adjustment of existing agreements relating to fiscal metering.

International research cooperation regarding improved oil recovery

Since 1979, Norway has participated in international research cooperation under the direction of the International Energy Agency (IEA) regarding improved oil recovery using advanced methods. Nine countries currently participate, and the cooperation largely consists of a commitment for a certain scope of research in specific areas and the exchange of the results. For the period 1986-1995, the Norwegian aspect of this cooperation has been taken care of through the state research programs SPOR and RUTH, which have been headed by the Norwegian Petroleum Directorate. From 1996 to 1996, the cooperation projects have been financed through the RESERVE program of the Research Council of Norway.

Since 1986, the Norwegian Petroleum Directorate has represented Norway in the international management committee for this IEA cooperation.

Assisting the Ministry of Petroleum and Energy in following up letters of intent to authorities in other countries

The Norwegian Petroleum Directorate's cooperation with Russia is mainly coordinated under the Norwegian-Russian Forum for Energy and Environment, which is headed by the Ministry of Petroleum and Energy. During the course of 1999, several seminars relating to this cooperation have been carried under the direction of the Russian Ministry of Fuel and Energy.

Lecture activities

Also in 1999, the Norwegian Petroleum Directorate's staff members have been involved as lecturers in a number of international conferences, workshops and the like, in issues relating to resources. These activities are in demand and they are regarded as being very important in order to contribute to a mutual exchange of information and experience. The Norwegian shelf receives international focus with regard to exploration efficiency, development concepts, resource exploitation and use of new technology. Openness regarding both the overall resource scenario and solutions chosen on specific fields has provided a basis for stimulation of technology and promising cooperative relations between participants on the shelf. There is still considerable interest on the part of other countries as regards gaining insight into Norwegian resource management and the authorities' active instigator role in this context.

4.4 COOPERATION WITHIN MANAGEMENT OF SAFETY AND WORKING ENVIRONMENT

RUN ARC - COMPREHENSIVE SAFETY AND ENVIRONMENT REGIME FOR OIL AND GAS ACTIVITIES ON THE RUSSIAN CONTINENTAL SHELF

Since the autumn of 1997, the Norwegian Petroleum Directorate has participated in a tripartite cooperation between Russian, American and Norwegian (RUN) authorities to investigate the possibility of developing a comprehensive safety and environment regime for the oil and gas activities on that part of the Russian continental shelf which lies in the Arctic (ARC).

The Ministry of Natural Resources is in charge of the project work on the Russian side. The Ministry cooperates closely with other authorities in Russia which are responsible for different aspects of regulation of the oil and gas activities in the country. The USA is represented by the Minerals Management Service (MMS), the technical authority on safety and the environment for inter alia offshore oil and gas activities. Based on experience from the previous "Boris" project, the Norwegian authorities have asked the Norwegian Petroleum Directorate to take responsibility for the Norwegian cooperation. The Ministry of Foreign Affairs finances the Norwegian part of the project.

The plan is to implement the project in three phases: preliminary study, development and implementation.

The first phase of the project, the preliminary study, was carried out from September 1997 to December 1998. This phase examined the current situation in Russia in the areas of safety and environmental legislation, responsibility of the authorities, safety management, emergency preparedness, environmental monitoring, etc. The results of this study are described in a report which also presents a number of proposals for what the Russian participants in the preliminary study believe must be done in order to develop a new safety and environment regime in Russia. After the preliminary study was completed with a report in 1998, the Russian working group worked on drafts for individual documents that will rectify some of the deficiencies uncovered in the preliminary study. It emerges from the report that the situation is complex for those who need to proceed through the Russian system, both as regards regulations and the powers of the various authorities. On the one hand, the regulations and the government system are characterized by overlapping requirements and authorizations, while, on the other hand, there are areas without clear requirements or defined authority.

Among the measures suggested is a rewriting of a number of laws and regulations, as well as examining the possibility of establishing one body that shall be responsible for governing safety and environment in the petroleum activities on the Russian continental shelf.

It is expected that a plan for the next phases of the project will be prepared by the end of the first half of 2000.

COOPERATION WITH RUSSIAN SUPERVISORY BODY - "THE BORIS PROJECT»

After a previous three-year project was completed in 1997, the cooperation with the Russian supervisory body for industrial safety, the Gosgortekhnadzor, was resumed in 1999. In 1999, the project activities concentrated on safety management and supervisory methods.

In 1997, Russia adopted a new act relating to safety in industry exposed to risk, where the principles on safety management and the companies' responsibility for safety were affirmed. In order to assist in the work of implementing this act, the Norwegian Petroleum Directorate arranged seminars dealing with experience from the Norwegian continental shelf relating to these areas. The industry's own responsibility with regard to safety management on installations on the Norwegian shelf, has been illuminated

International cooperation

in presentations by both operator and contracting companies. The authorities' role in the safety work was described in a review of the regulatory framework and a presentation of the methods for planning and carrying out supervision of safety on the Norwegian continental shelf.

INTERNATIONAL COOPERATION AGENCIES

The Norwegian Petroleum Directorate cooperates extensively with international technical institutions and government agencies, either directly or indirectly through Norwegian government agencies. The purpose of this cooperation is to:

- contribute to ensuring that safety and the working environment in the petroleum activities at least meet accepted international standards,
- ensure access to relevant information for competence building and regulatory development,
- contribute insight and experience in an international context in order to promote positive development in safety and working environment.

In general, the cooperation has consisted of participation in international governmental cooperation in Europe and in agencies of the United Nations, but also more direct cooperation with the various types of international and regional professional institutions. The most important partners in 1999 have been:

- NSOAF - North Sea Offshore Authorities Forum,
- IRF - International Regulators Forum
- the EU Commission, in cooperation with the Ministry of Local Government and Regional Development, on safety and the working environment,
- the United Nations' organizations IMO and ILO regarding safety at sea and the working environment, respectively,
- the United Nations' organization UNEP IE regarding environmental measures in offshore petroleum activities,
- European Diving Technology Committee (EDTC) and the Association of Offshore Diving (AODC) regarding diving safety,
- American Petroleum Institute (API); participation in the annual conference on technical petroleum topics and standardization,
- National Association of Corrosion Engineers (NACE), USA; participation in the annual conference on corrosion and surface treatment,
- CENELEC; cooperation on electrical engineering standardization in Europe through the Norwegian Electrotechnical Committee (NEK).
- Bilateral cooperation between the Norwegian Petroleum Directorate and similar supervision authorities in Denmark, the Netherlands and the United Kingdom.

NSOAF - North Sea Offshore Authorities Forum

In the field of Health, Safety and Environment, the Norwegian Petroleum Directorate participates in the North Sea Offshore Authorities Forum (NSOAF), where representatives from all the North Sea countries' governmental authorities in charge of supervision of offshore petroleum activities take part. The goal of the forum is to ensure continuous improvement in health, safety and the environment in the petroleum activities in the North Sea.

The members of NSOAF meet for an annual working meeting where the activities are summarized and new tasks are discussed and initiated. Two independent working groups have been appointed by the forum and the Norwegian Petroleum Directorate is represented in these.

One of the groups is working with the aim of mutual acceptance of methods for documenting compliance with national regulatory requirements, such as the "Safety Case", which is specific to the individual mobile installation. This group is chaired by a Norwegian.

Audit teams have been established under this working group made up of representatives from several of the member countries. These teams conducted joint audits on mobile drilling installations. These supervision activities were completed in 1999. The activities were focused on maintenance management and were carried out on a total of five drilling installations on the continental shelves of different countries. The experiences were summarized in a separate report and is considered to be positive, both as regards development of a common understanding of different regulatory and supervisory strategies and as regards the actual findings and observations. The experience from the international activities is an important contribution to further cooperation in an NSOAF context in order to unitize and harmonize important authority issues in the North Sea basin.

The other group, which has a Danish chairman, will seek to harmonize the requirements for safety training in the various North Sea countries. So far, the member countries have agreed on which elements of the training programs are mutually acceptable and in which areas there are different requirements. In the next phase of the work, the working group will explore the opportunities for mutual acceptance of different types of special training.

IRF - International Regulators Forum

The International Regulators Forum (IRF) was established in 1994 by a group of authorities who wanted to promote a common understanding of issues related to safety, health and the environment.

The forum provides for exchange of ideas and opinions regarding methods and principles applied to efficient exercise of the supervision of safety and working environment, and exchanges facts regarding the supervision activities and informs one another regarding topical technical issues, regulatory developments, etc.

Within the possibilities and limitations stipulated through national frameworks for the activities, this will contribute to promoting a common understanding among the members with regard to issues such as: the role of the supervision authorities, use of policy instruments in the supervision, supervision methods, competence development, the relationship between the authorities and industry, etc.

The following participate in the cooperation in addition to Norway: Australia, the Netherlands, Canada, the UK and the USA. An increase in the number of participating countries is being considered.

The Norwegian Petroleum Directorate hosted the annual forum meeting in the autumn of 1999. The meeting had a comprehensive agenda, including improving the efficiency of the authorities' policy instruments. Key issues in this context were regulatory development, safety training and development of management systems. Reporting of injuries and standardization were also addressed. The technical part of the program included issues related to risk associated with mobile installations, reporting of work-related illnesses and injuries on installations, as well as questions surrounding removal/disposal of installations.

The EU Commission

Since 1982, Norway, represented by the Norwegian Petroleum Directorate, has held observer status in the EU proceedings on safety and the working environment in offshore petroleum activities.

This work comes under the EU's "Safety and Health Commission for the Mining and Other Extractive Industries" (SHCMOEI), and the work is carried out by a working group called the Committee on Borehole Operations.

The work of the Committee on Borehole Operations includes following up the work on harmonizing requirements relating to safety training in the North Sea countries.

The Committee on Borehole Operations is also continuing its work regarding personal injury statistics for the offshore petroleum activities. Special attention is being given to lifting operations between vessels and permanent/mobile installations in this work.

UNEP - United Nations Environment Programme

The Norwegian Petroleum Directorate is involved as a contributor in a forum for environmental issues in offshore petroleum activities under the direction of the United Nations' organization, UNEP. The forum is an interactive, Internet-based information system with free access. The system contains information regarding pollution sources, effects of pollution, as well as information regarding management, technology, legislation, training programs, etc.

Other contributors include the Dutch authorities, the oil industry through the E&P Forum, Brazil's Petrobras, the World Wildlife Fund and UNCTAD. The forum's web address is: www.natural-resources.org/offshore.

5.1 DELEGATIONS

The duties of the Norwegian Petroleum Directorate are set out in the special instructions of 1 October 1992. Duties have also been assigned to the Norwegian Petroleum Directorate by delegation of authority. Such authority is delegated either directly pursuant to acts/regulations or by individual administrative decisions by a superior authority. Delegation applies to:

a) The Petroleum Act of 29 November 1996, No 72
Including:
The Petroleum Regulations, Royal Decree of 27 June 1997
The Safety Regulations, Royal Decree of 27 June 1997
The Internal Control Regulations, Royal Decree of 27 June 1997
The Safety Zone Regulations, Royal Decree of 9 October 1987

b) The Working Environment Act of 4 February 1977, No 4
Including:
The Working Environment Regulations, Royal Decree of 27 November 1992
c) The CO_2 Act of 21 December 1990, No 72
d) The Tobacco Act of 9 March 1973, No 14
e) Act relating to scientific research and exploration for and exploitation of subsea natural resources other than petroleum resources, Act of 21 June 1963 No 12
Including:
Regulations relating to scientific research for natural resources on the Norwegian continental shelf, etc., Royal Decree of 31 January 1969
f) Regulations concerning safe practices in scientific research and exploration for petroleum deposits on Svalbard, Royal Decree of 25 March 1988

5.2 ACTIVITY PLAN

The annual activity plan is based on guidelines and requirements for the activities of the NPD as described in the letter of award. The plan consists of one governing objective and six main objectives with underlying targets and activity plans. The governing objective was adjusted in the autumn of 1999.

The Norwegian Petroleum Directorate shall contribute to creation of the highest possible values for the society from oil and gas activities founded on a sound resource management, safety and environment.

In 1999, the six main objectives were:

1. Continue development of the NPD as a professional organization with a high level of technical expertise in a national and international context
2. Ensure that the petroleum activities are carried out safely and resources are exploited in a prudent manner in a comprehensive long-term perspective
3. Maintain an overview of and assess current and future petroleum activities, petroleum resources and safety levels on the Norwegian continental shelf
4. Continuous development of framework conditions in order to ensure they are suitable and adapted to national and international development
5. Contribute to Norway becoming a pioneer regarding environmental considerations in the petroleum activities
6. Support internationalization and development aid through active use of the NPD's expertise and contacts

5.3 ORGANIZATIONAL CHANGES

The Petroleum Resource Management Division was reorganized into a team-based organization as of 1 February 1999. The Division is now led by a team composed of the Division Director, four technical coordinators and eight process advisors. Approximately 40 self-run teams work on product-related tasks. The reorganization resulted in changes in the regional office in Harstad as each individual employee now reports directly to their unit in Stavanger.

Based on a pilot project in 1998, the Director General decided to carry out an organizational development project, "NPD 2000 and beyond", during 1999 and 2000. The vision is to create a unified and efficient NPD that will be able handle future challenges within the oil and gas activities on the Norwegian shelf. The project is well founded within the organization with a dedicated management group, program committee and three working groups, as well as advisors from external consultancy firms. The work takes the form of internal meetings and seminars. A program for the project, a report on external challenges and opportunities and an overview of the current work processes were prepared in 1999. In addition, an analysis of the working environment was carried out and the reform work has been initiated.

During the course of 2000, the project will make the conditions and terms for organizing the future NPD more specific and prepare an organizational model for meeting these requirements. According to the plan, the new organizational model will be implemented at the end of 2000/beginning of 2001.

5.4 STAFF

At the end of 1999, the Norwegian Petroleum Directorate had 372 employees. Twenty employees were on leave. Fifty-eight per cent of the employees are men and 42 per cent are women, the same as in 1998.

Eighteen new employees were hired in permanent positions. Of these, eight came from oil-related activities, eight from other private industry or the public sector and two came directly from educational institutions.

Fourteen staff members have left, seven of these as retirees. This represents 3.8 per cent of the positions.

A new governing competence training plan has been prepared that provides for increased focus on the staff-members' expertise on all levels.

In 1997, it was decided that the share of female managers at the senior and middle management level should be increased to at least 30 percent by the end of 2001. The proportion of women in these positions was at 23 percent in 1999. This is an increase of four percent compared with the previous year.

5.5 BUDGET/ECONOMY

Expenses

A total of NOK 267,792,637 was spent on the Norwegian Petroleum Directorate's operations in 1999.

The amount was appropriated as follows:

Operating costs	228,780,250
Supervision costs	13,942,260
Geological and geophysical surveys	25,070,127
Total	**267,792,637**

Of the operating budget, payroll costs account for NOK 148,929,350 (including employers' contribution), lease and operation of buildings account for NOK 32,176,688, and expenses in connection with consultancy assistance accounted for NOK 8,248,082.

The remainder, NOK 39,426,130, covers expenses related to travel, training, electronic data processing (EDP) operations, new investments in equipment, etc.

In addition to its regular operations, the Norwegian Petroleum Directorate is responsible for:

Cooperation projects	9,901,589
Commissioned activities	15,892,209
Contribution to the PETRAD foundation	3,000,000
Project cooperation vis-à-vis Eastern Europe	804,345
Total	**26,598,143**

Revenues

In addition to paid production royalties, area fees and CO_2 taxes totaling NOK 7,044,615,208, the Norwegian Petroleum Directorate received NOK 97,423,612 in revenues:

Fee and tax income	2,917,586
Commission and cooperation income	25,998,782
Reinbursed supervision costs	53,119,448
Sale of survey material	3,600,185
Sale of publications	2,286,225
Miscellaneous income	1,945,942
Kindergarten fees	3,359,100
Reinbursed for rent	788,779
Reinbursed for job schemes	658,871
Reinbursed for maternity/adoption allowances	2,563,694
Reinbursed for apprentices	185,000
Total	**97,423,612**

5.6 INFORMATION

The Norwegian Petroleum Directorate's publication Sokkelspeilet (Norwegian Petroleum Diary) is published quarterly in Norwegian and English versions. The main objective of the publication is to reflect the activity on the Norwegian continental shelf. The Norwegian Petroleum Diary will provide background information and assess consequences, contexts and ripple effects, as well as focus on the main trends in the Norwegian petroleum activities. The target group for the periodical consists of the authorities in Norway and other countries, the oil industry and other business and industry, educational and research institutions, the media, labor unions and society at large.

There is a great deal of interest in the Norwegian Petroleum Diary. Good feedback as well as a doubling of the number of subscribers during the first year shows that issuing the publication was a correct move by the Norwegian Petroleum Directorate.

The annual report occupies a central position in the Directorate's information activities, as does the continental shelf map, which was published in 1999 with production licenses updated as of 9 June 1999.

Forty press releases have been issued by the Norwegian Petroleum Directorate in 1999, most of them in connection with the conclusion of exploration wells. Three issues of the Directorate's internal magazine "Oss Direkte" were published and the internal publication "Info-ekspressen", containing newspaper clippings from petroleum-related national and international news, was issued about 25 times.

Other publications issued in 1999 are listed in the next section.

The Norwegian Petroleum Directorate's home page on Internet may be found at http://www.npd.no, and contains inter alia special reports and information concerning the Directorate's sphere of responsibility. Press releases, daily mail journal and references to new publications are entered continuously. The information is available in both Norwegian and English and is searchable. The public can subscribe to press releases by registering their e-mail address on the home page. There were an average of 34,000 visits to the home page per month, an increase of 30 per cent from 1998.

Use of the Nordic reference database OIL on the Internet http://www2.interpost.no/oil increased by about 19 per cent to about 50,000 hits in 1999. There were somewhat more than 4,000 hits per month divided among approximately 700-800 different institutions. The operating companies are the largest users of OIL, but many schools also use the database regularly. Hyperlinks have been set up to several publications that are accessible in full text format. The database is also accessible from the home page of the Norwegian Petroleum Directorate.

1500 applications for inspection of documents under the Freedom of Information Act were processed. This is an increase of 50 per cent compared with last year. The Directorate's public mail lists are sent to a common public service mail journal database. Selected groups from the Norwegian press have access to the database. Orders are transferred electronically to the Norwegian Petroleum Directorate. The public post lists have also been accessible from our web site under Information services as of the summer of 1999.

An internal five-year project relating to electronic case processing (ElSak) was initiated in 1999. The objective is to raise the quality and efficiency of the case processing using IT support. This year, the main focus of the project has been:

- work flow system for testing the consent process
- gathering of data for the national budget on the SOIL Extranet using the WebWare software
- establishing an electronic test archive.

5.7 PUBLICATIONS RELEASED IN 1999

The list of publications contains 153 different publications, of which 35 were reissued publications. Fourteen publications can be read in their entirety on the web site, including the Norwegian Petroleum Diary as of issue No. 2/1999.

An up-to-date list of publications can be found on our home page http://www.npd.no under Information services.

Acts, regulations and guidelines

- Compilation of Acts, regulations and provisions for the petroleum activities in 1999. An updated compendium of the acts, regulations and guidelines applicable to the Norwegian continental shelf. Issued 1 June 1999.
- Act relating to worker protection and working environment
- Regulations to Act relating to petroleum activities
- Regulations relating to worker protection and working environment
- Regulations relating to drilling and well activities and geological data collection, etc.
- Regulations relating to lifting appliances and lifting gear, etc.
- Regulations relating to load-bearing structures, etc.
- Regulations relating to electrical installations, etc.
- Regulations relating to pipeline systems, etc.
- Regulations relating to process and auxiliary facilities, etc.
- Regulations relating to safety and communication systems, etc.
- Regulations relating to systematic follow-up of the working environment, etc.
- Regulations relating to fiscal measurement of oil and gas, etc.
- Regulations relating to measurement of fuel and flare gas for calculation of CO_2 tax, etc.
- Regulations relating to manned underwater operations, etc.
- Regulations relating to emergency preparedness in the petroleum activities
- Interfaces in legislation applicable to the Norwegian continental shelf
- Interfaces in legislation applicable to the Norwegian continental shelf

Other publications

- List of publications issued by the Norwegian Petroleum Directorate
- Sokkelspeilet (Norwegian)
- Norwegian Petroleum Diary (English)
- Oljedirektoratets årsberetning 1998 (Norwegian)
- NPD Annual report 1998 (English)
- Report from the DSYS diving database in 1998 (Norwegian)
- Miljø 1999 - Petroleumssektoren I Norge (Norwegian)
- Environment 1999 - The Norwegian Petroleum Sector (English)
- Clean-up of the seabed in the North Sea 1998 (Norwegian)
- Petroleumsressursene på norsk kontinentalsokkel 1999 (Norwegian)
- The petroleum resources on the Norwegian continental shelf 1999 (English)
- Licences, Areas, Area-coordinates, Exploration Wells (English)
- Borehole list - Exploration Drilling (English)
- Development Wells (English)

Organization

5.8 ORGANIZATION CHART